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AN ASSESSMENT OF WIND CHARACTERISTICS AND WIND ENERGY CONVERSION SYSTEMS FOR ELECTRIC UTILITIES

WISCONSIN POWER PLANT IMPACT STUDY

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Wisconsin Power and Light Company,
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Evaluation of wind speed data from 12 airport sites in Wisconsin, Minnesota, Iowa, and Illinois, and from five Coast Guard stations along Lakes Superior and Michigan, indicates annual average wind speeds of 4.5 to 6 m/s and wind power densities of 100 to 200 W/m^2 at 7 m height. The economic analysis of wind energy conversion systems (WECS) applied to the Dairyland Power Cooperative (DPC) system indicates that it can be economically attractive for the DPC to install WECS in the 1980s. This analysis does not include benefits due to the potential replacement of conventional capacity by the WECS. A preliminary study of WECS in combination with directly controlled water heaters shows that this combined system may delay conventional generating capacity additions longer than will controlled heaters only. A detailed reliability and cost production analysis of WECS plus direct control of a variety of loads is required to evaluate these systems accurately.

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FOREWORD

The U.S. Environmental Protection Agency (EPA) was created because of increasing public and governmental concern about the dangers of pollution to the health and welfare of the American people. Polluted air, water and land are tragic testimony to the deterioration of our natural environment. The complexity of that environment and the interplay between its components require a concentrated attack on the problem.

Research and development, the necessary first steps, involve definition of the problem, measurements of its impact, and the search for solutions. The EPA, in addition to its own laboratory and field studies, supports environmental research projects at other institutions. These projects are designed to assess and predict the effects of pollutants on ecosystems.

One such project, which the EPA has supported through its Environmental Research Laboratory in Duluth, Minnesota, is the study "The Impacts of Coal-Fired Power-Plants on the Environment." This investigation, carried out by the Institute for Environmental Studies of the University of Wisconsin-Madison, in cooperation with the Wisconsin Power and Light Company, Madison Gas and Electric Company, Wisconsin Public Service Corporation, Wisconsin Public Service Commission and the Wisconsin Department of Natural Resources, is monitoring and evaluating the impacts of a new coal-fired power plant on the immediate environment.

During the next year reports from this study will be published as a series within the EPA Ecological Research Series. These reports will include topics related to chemical constituents, chemical transport mechanisms, biological effects, social and economic effects, and integration and synthesis.

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ABSTRACT

Evaluation of wind speed data from 12 airport sites in Wisconsin, Minnesota, Iowa, and Illinois, and from five Coast Guard stations along Lakes Superior and Michigan, indicates annual average wind speeds of 4.5 to 6 m/s and wind power densities of 100 to 200 W/m^2 at 7-m height. The economic analysis of wind energy conversion systems (WECS) applied to the Dairyland Power Cooperative (DPC) system indicates that it can be economically attractive for the DPC to install WECS in the 1980s. This analysis does not include benefits due to the potential replacement of conventional capacity by the WECS. A preliminary study of WECS in combination with directly controlled water heaters shows that this combined system may delay conventional generating capacity additions longer than will controlled heaters only. A detailed reliability and cost production analysis of WECS plus direct control of a variety of loads is required to evaluate these systems accurately.

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SECTION 1

INTRODUCTION

Wind energy played an important historical role in the development of many countries by providing a major form of transportation (sailing ships) and mechanical power (windmills). Fossil fuels have gradually replaced these wind energy technologies. Today however, public interest in many countries is turning toward applications of wind and solar energy technologies in light of the problems relating to the use of fossil and nuclear fuels. The recent increase in the U.S. federal solar research and development budget reflects this public interest to some extent.

Wind-powered electric generators were developed in Denmark near the end of the last century. Hundreds of wind electric generators proved to be a reliable power source in that country, particularly during World Wars I and II. Windmills operated in Denmark until the early 1960's, when cheaper steam-powered generators replaced them. Similar events occurred in several other countries. Many small electric windmills were used in the United States until 1935 when the publicly subsidized Rural Electrification Administration (REA) provided electricity to farms. France, Britain, Germany, and Russia have experimented with wind machines of different design, but unfavorable economic conditions killed these projects.

Thus, windmills or wind machines represent an old proven technology. New developments in materials, control techniques, and electronics will improve performance, lower costs, or both. Presently, capital and operating and maintenance costs of wind energy conversion systems (WECS) are uncertain, which is largely due to the as yet unknown effects of assembly-line production techniques and of economics of scale (large versus small wind machines). However, it can be argued that industrialized societies have a good record of mass-producing relatively simple technology at low cost (cars, calculators, electric generators/motors). Thus, it seems likely that reliable wind machines can be built in the near future in large quantities at a relatively low cost. Environmental consequences and regulatory issues related to WECS appear to be predictable.

Recent studies indicate that nuclear costs are rising sharply and are not exactly known. By the end of 1975, nuclear capital costs were unknown, with more than 100 light water reactors (LWR) under construction or in operation (Bupp and Derian 1978). Some 20 yr after the first LWR began operating, costs have not yet stabilized. In addition, increasing national and international regulations as well as a growing uncertain political climate towards nuclear power contribute to an unpredictable future. A reliance on coal also faces high and uncertain costs, as well as many associated health and environmental problems. The combination of increased cost for land reclamation, transportation system renewal, and the (partial) internalization of presently external health-related costs will most likely increase the price of coal and coal-fired power plants faster than the general inflation rate.

Wind energy conversion systems can be installed without a long lead time, thereby increasing the planning flexibility. Additions of WECS capacity can be made on an incremental basis and adapted to local circumstances. Furthermore, the diversity in the energy resources employed becomes larger. These factors are important in times of uncertainty. The resilience of the energy system, that is the capacity to "absorb and utilize (or even benefit from) change" (Holling 1976), will increase when WECS are utilized. This may be the most important reason to install and use WECS and other solar technologies now.

The variation in the wind over time means that a given power output cannot be guaranteed, unless storage devices are included. Thus, wind electric systems are unlike the existing form of generating electricity. Furthermore, the capacity of WECS is small in comparison to the typical central generating plants. A detailed analysis is required to assess economic benefits and fuel savings for a WECS interconnected with a utility system. Such an analysis is included in this report.

Wind data presently available are not sufficient for an accurate assessment of WECS. The wind speed data used in this study generally underestimate the power in the wind. Since a significant part of the utilities' load in northern regions is for heating purposes (low-quality energy needs), it is suggested that thermal storage devices can be used in conjunction with WECS to overcome the variability in the wind. This is particularly true for those utilities that have a load with a positive correlation with the wind availability, like the Dairyland Power Cooperative (DPC), La Crosse, Wisconsin. This study includes an analysis of WECS plus active thermal load control.

Wisconsin is one of the few states that does not have known fossil or uranium reserves. Approximately 99% of the energy used is imported from other states. Energy consumption by fuel type shows the following percentages of total use in 1976: 40% petroleum, 27% natural gas, 23% coal, 9% nuclear, and 1% hydro (Aigner et al. 1977). Substitution of the nonrenewable (stock) resources by renewable (flow) resources would make Wisconsin less dependent on energy imports and improve the balance of payments. An active public policy to promote solar energy technologies could create an important new industry and many jobs for the state of Wisconsin. If such a policy is not adopted soon, Wisconsin will fall behind other states that stimulate the use and manufacturing of these technologies.

An important characteristic of Wisconsin is the spatial distribution of its population and activities. About 33% of the population live in rural areas: Open country, towns, or villages of less than 2,500 people (Stern et. al. 1974). In addition, the megalopolitan area of Milwaukee (the Standard Consolidated Statistical Areas of the U.S. Census Bureau) shows a net population migration out of the urban areas during 1970-74, an unanticipated movement (U.S. Bureau of Census 1977). Fifty-four of the 72 counties have a population density lower than 100 persons/mile^2 (40/km^2). Thus, these rural areas represent a large geographical part of the state. Since renewable (flow) energy resources are particularly suitable for decentralized energy use patterns, a study of the potential of wind (and other solar) energy as a partial replacement of the conventional supply system in rural Wisconsin appears to be desirable. Note that renewable (flow) resources can be used effectively in urban areas too. It seems easier, however, to balance dispersed energy resources with dispersed energy use. For these reasons, the study of wind energy applications on the DPC focused on a rural based REA cooperative.

The structure of this report is as follows. A literature review of wind characteristics in Section 3 is succeeded by the results and discussion of the analysis of wind characteristics in Wisconsin and sections of the surrounding states in Section 4. Wind speed and wind power data are presented in detail in Appendices A and B. Section 5 reviews the major characteristics of wind machines pertinent to this study. The power output of a selected number of wind machines in Wisconsin and sections of the surrounding states is given in Section 6 and Appendix C. Appendix D displays power output duration curves of the selected wind machines. Section 7 contains the major analysis of wind energy conversion systems (WECS) applied to the DPC. The analysis pertains to wind machines roughly varying in size from 10 kW to 1,000 kW and owned by the DPC, although some issues related to privately owned, winter-connected wind machines are briefly discussed in Section 8. Since the utility's system reliability model was not available for this study, the analysis is limited to electricity production costs considerations, only. Benefits of the potential elimination of the need for some conventional generating capacity are not included. Thus, the results are a conservative estimate of the benefits of WECS. Section 8 discusses the positive correlation of wind availability and DPC's load, control of DPC's growing heating load, and the potential of combining WECS and load control to meet DPC's peak load. Conclusions and recommendations can be found in the last two sections.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Annual average wind power densities generally vary between 100 and 200 W/m^2 at 7-m height in the runway area of 12 airports assessed in Wisconsin and surrounding states. A height adjustment with the 1/7-power law to 60-m height results in power densities between 250 W/m^2 and 500 W/m^2. Annual average wind speeds vary between 4.5 m/sec and 6 m/sec at 7 m and between 6 m/sec and 8 m/sec at 60 m. Wind energy availability at Coast Guard stations along Lakes Superior and Michigan is similar to or better than those of the airports. The importance of local features is indicated by the significant difference between power densities at Rochester, Minnesota and La Crosse, Wisconsin approximately 80 km (50 miles) apart with annual wind power densities of, respectively, 517 and 152 W/m^2 at 60-m height. A wind energy survey is necessary to identify locations in Wisconsin with wind characteristics in or above the upper range of the locations assessed in this study. Appendices A and B contain wind speed and power data for each airport location analyzed.

The specific energy output of a wind machine (kWh/kW/yr) is approximately a linear function of the annual average wind speed ($\overline{V}$) of the locations assessed in this study, except for extreme values of $\overline{V}$. A similar relationship is shown by other authors. This relationship can be used to estimate the annual energy output of a wind machine with a given rated power density, if the annual average wind speed is known. The seasonal variation of wind machine power output and power output duration curves are helpful in the evaluation of WECS. Appendices C and D display these data for three wind machines with rated power densities of 90, 220, and 305 W/m^2.

The capacity of wind machines presently on the market is generally in the 1 to 15 kW range, although a few companies now offer wind machines with higher capacities. Present costs per kW of capacity range from about $500 to $1,500. The future cost of wind machines is uncertain, largely because the effects on cost of assembly-line production techniques and economies of scale (large versus small wind machines) are unknown. The present Research and Development program of the U.S. Department of Energy, efforts of private industry, and programs overseas will probably result in a variety of reliable wind machines by the early to mid-1980s at competitive costs below $1,000/kW (1978 dollars). In addition to these uncertainties as to capital cost, operation and maintenance (O and M) annual cost estimates for WECS range from about 0.5 to 3% of the investment.

Uncertainties in the cost of wind machines appear to be smaller than those in the coal and nuclear technologies. Windmills represent an old proven technology. During the first 60 yr of this century, wind (electric) machines generally showed a satisfactory technical record. These machines ceased to be employed because of unfavorable economic conditions during an era of low, decreasing fuel prices. New developments in materials, control techniques, and electronics will improve the performance of the wind machines, bring costs down, or both. Nuclear and coal technologies, on the other hand, face a future that is hard to predict. Sharply rising costs of capital equipment and fuels, increasing national and international regulations, as well as a growing uncertain political climate towards nuclear power contribute to this unpredictable future.

Analysis of a 1985 WECS addition to the DPC proposed expansion plan indicates that, with the assumptions made, production costs saved exceed the estimated capital, O and M, and insurance costs during the lifetime of the wind machines. Thus, wind machines will save valuable fuels and money. WECS fail to be economically competitive only if fuel prices increase at a lower annual rate than about 9 to 10% (including inflation) during the period 1992-2020 and if wind machine cost estimates of $700 to $1,000/kW (January 1979 dollars) are too optimistic.

The break-even cost of wind machines decreases when the WECS capacity added in 1985 is increased from 100 to 400 MW (11 and 44% of the 1985 conventional capacity, respectively). But this decrease is not large because of the characteristics of the DPC generators. WECS capacities lower than 100 MW (not included here) may show higher economic net benefits. This will largely depend upon the possible increase in wind machine capital and O and M cost. Note that the analysis presented here does not include so-called "capacity credits." Furthermore, the wind data employed are for airport locations, which do not represent the best WECS sites. Therefore, the benefits of WECS calculated are a conservative estimate. It is emphasized that analyses of alternative expansion plans are sensitive to the assumptions made.

The assessment of synchronous hourly load and three hourly wind power data for 1969 to 1973 shows a strong positive correlation between the DPC load and wind availability. The space heating component of the DPC load and similar diurnal variation in load and wind power during the summer months contribute to this correlation, which improves the economic and technical viability of WECS. The DPC is a utility that has a winter peaking system. Other utilities with a winter peaking load are the Cooperative Power Association, Lake Superior District Power Company, and the Northern States Power Company, Wisconsin. Wisconsin Public Service Corporation peak demands during winter and summer are projected to stay about equal. Other Wisconsin utilities predict a summer peaking load throughout the 1980s (Western Wisconsin Utilities 1978; Schoengold 1978--personal communication).

A WECS plus load control system may meet the peak load with equal or better reliability than conventional peak-load generators. This is due to the positive correlation between the DPC load and wind power availability. A WECS capacity of 1 to 1.33 times the peak-load range plus a controlled load of water heaters of 25% of the WECS capacity meet the peak load about 93 to 96% of the time and save 94 to 99% of peak-load fuels and 10 to 15% of other fuels. The WECS break-even costs appear to increase by at least 10 to 15% when combined with load control. Furthermore, the combination of WECS and load control systems may eliminate or delay the need for additional conventional generating capacity (also dependent upon growth in load). A detailed reliability and production cost analysis of WECS plus control of a variety of loads is necessary to evaluate these systems accurately.

WECS and load control can be installed without a long lead time, which results in an increased flexibility of the planning process. Since wind machines have not been produced in large quantities yet, an example of rapid increase in industrial manufacturing capacity is given for a technology that has some analogies with WECS (reported in a FEA Project Task Force Report, quoted here from Grossman and Daneker 1977):

> ...but on some occasions when this country needed vigorous action, even the federal bureaucracies and private industry responded. For example, when specialized aircraft were needed during World War II, the fledgling aircraft industry was able to increase production from 3,623 in 1938 to 96,318 in 1944. The FEA concluded: It is assumed that wind energy systems are not more difficult and probably far less difficult to produce than World War II aircraft.

Active load control systems can be installed within a period of about 2 yr (Nelson 1976). On the other hand, licensing and construction of nuclear power plants may take as long as 12 yr.

In addition to the increased flexibility to meeet the changing energy needs of society in a variety of ways by WECS plus load control (and other solar technologies), the diversity of the electric generating mix becomes larger. The importance of diversity has been shown to some extent during a coal strike several years ago, when western coal and nuclear power provided electricity to regions that normally use eastern coal.

Holling (1976) ties concepts of uncertainty, flexibility, diversity, resilience, and stability of systems together in an article "Myths of Ecology and Energy." Holling suggests restructuring the energy system in a way that increases its resilience. The present emphasis on engineering for safety seems to result in the opposite. Although the probability of failure of nuclear power plants, for example, is generally agreed to be small, the high cost of failure makes the trial and error method dangerous. Technologies of incremental nature and consisting of diverse components, such as many technologies that use renewable (flow) resources, will increase the resilience of the energy system. This factor cannot be easily measured in economic terms and, therefore, seldom enters the decision-making process as to the choice of alternative technologies.

But it should be realized that the role of an economic analysis in decision-making is that of only one input out of a large number. An increase in the resilience of the nation's energy system may be the most important reason to install and use WECS and other solar energy technologies.

Incentives could play an important role in promoting the use of WECS. A property tax exemption for DPC WECS will increase the break-even capital cost of a WECS by about 20%. The availability of loans to the DPC with a 7% instead of 9% interest rate will increase the WECS break-even cost by about 35%.

The member distribution cooperatives of the DPC may play a more active role in planning, operating, and maintaining the electric system, if dispersed technologies like WECS and controlled heat/cold storage systems are installed. More local jobs would then be created, and state and federal regulations as to the choice of operation of these energy systems might be reduced.

The issue of electricity rates for individuals/farms/firms that own and operate a WECS interconnected to the utility's network, with or without a controlled storage system, requires a careful study.

Conclusions about WECS added to the DPC proposed expansion plan cannot be easily generalized for other utilities, because the load characteristics of the utilities differ significantly. It appears likely that utilities with an important rural load may find WECS economically feasible, too. A detailed production cost and reliability analysis is required for each utility to obtain an accurate assessment of WECS.

RECOMMENDATIONS

The following recommendations are particularly directed to the DPC, but in several cases also pertain to other utilities:

(1) Investigate the possibility of participating as soon as possible in the DOE wind energy demonstration program of large as well as small WECS. Participation will result in experience with the hardware, power conditioning, and O and M. In addition, time series analysis of load and WECS power output will help in designing an equitable rate structure for WECS owners and can be employed to verify the study reported here.

(2) Study the development of the wind machine manufacturing capacity of United States industries to assess the possibility of installing 100 to 200 MW of WECS by the year 1985. Turnkey contracts may be obtained for wind machines in the range of 10 kW to 1 MW. Turnkey contracts are defined by Webster as "a job or contract in which the contractor agrees to complete the work of building and installation to the point of readiness for operation or occupancy."

(3) Initiate a wind energy survey to find locations that have a good wind availability and that are close to suitable load centers. Federal as well as state funds may become available for such a survey.

(4) Evaluate the suitability of reducing total conventional capacity or changing the mix of peak, intermediate, and base-load generators when WECS are added to the proposed plan. Both the cost of production and the reliability of models have to be employed. This evaluation could be made in close cooperation with the Electric Power Research Institute which is presently involved in WECS-utility-reliability studies.

(5) Assess a combined WECS and load control system by employing the production cost and reliability models as described in Section 8. The change in the mix of generators, possibly a delay in base-load capacity needs, as well as increased possibilities of load control require careful study.

(6) Investigate the relation between the DPC and the member distribution cooperatives when dispersed WECS are planned, installed, operated and maintained. Increased local control and the creation of local skilled jobs are two aspects of these dispersed systems that cannot or do not always enter economic evaluations.

(7) Reevaluate the growth in space and water heating as well as other loads that can be controlled. The projected increase in load control and off-peak storage is not sufficient to offset the growth in peak load due to energy substitution from LPG and oil to electricity. It is necessary to question whether consumers have the right of electric utility service without any restrictions as to the electric heating systems installed. One can envision mandatory controlled space and water storage heating systems to reduce the growth in electric peak demand.

The following recommendations are directed towards state agencies (Wisconsin Office of State Planning and Energy, Wisconsin Public Service Commission) and utilities in general:

(8) Participate in the DOE demonstration and test programs of small as well as large WECS throughout the state in the residential, commercial, agricultural, and industrial sectors.

(9) Initiate a state-funded demonstration/test program of WECS to complement the federal program. Such a state program may serve as a "market-pull" model to increase the WECS production capacity, particularly the one within the state to create skilled jobs.

(10) Create additional incentives such as property tax exemptions (similar to exemptions for environmental control facilities) and low interest loans (similar to the federal REA loans that effectively eliminated windmills in the 1930s and 1940s) for WECS owners, including utilities.

(11) Address the problem of the sale of electricity by nonutilities back to the utility or third parties.

(12) Start a wind energy survey to identify locations that have a good wind availability and that are close to utility load centers. Existing weather bureaus, utility meteorological programs, and newly chosen locations should be combined for a wind speed time series data base to be used by utilities and others.

(13) Include a detailed evaluation of WECS in the assessment of Wisconsin Utilities Advance Plans. These analyses should not only include production costs comparisons, but also address issues like a change in the mix of conventional generators (less base-load units) and/or a reduction in conventional generating capacity, the value of flexibility (shorter planning lead times, maintenance planning of small units), diversity in energy resources, and the increased potential of load control (less problems with creating new peaks during payback periods).

(14) Assess the nature of the utilities' load as to the energy quality of consumers' needs. An increasing part of the load consists of low-quality energy, requiring tasks, such as space conditioning and water heating that can be met by energy sources of lower quality than electricity. A study of matching quality of energy sources and needs should evaluate:

    (A) The question whether the second law of thermodynamics should be used to set priorities as to the type of consumer activities served.

    (B) The suitability of using WECS for space heating, even though the electricity generated could be used for higher energy quality needs.

(C) The advantage of having some low quality load that can be met by thermal storage systems, thereby greatly increasing the possibility of flattening daily load curves, versus priorities in services set by means of the second law of thermodynamics.

SECTION 3

WIND CHARACTERISTICS: LITERATURE REVIEW

WIND DATA SOURCES

The National Climatic Center (NCC), Ashville, North Carolina, collects and processes meteorological and climatological data from within the United States. The observations are made by the National Weather Service, Federal Aviation Administration, military services, merchant marine vessels, Coast Guard stations, and some locally operated airfields (Changery 1975). In addition, some data at electric generaton sites are available from electric utilities (Verholek 1977).

Data of at least a 5-yr period are necessary for preliminary description of the wind climatology of a location (Changery 1975). NCC wind data on land are hourly observations obtained between 3 and 30 m from the ground. The majority of these observations are made at airport and city locations, which can be significantly different than at surrounding locations. Most of the hourly data between 1940 and 1964 are digitized. Since 1965, only three hourly observations are digitized, although the originals are also available. The height of the wind observations since 1965 is about 7 m (20 ft.) above the ground in the runway area of the airports.

The NCC hourly wind speed observations are 1-min averages once each hour. Studies indicate that the true hourly averaged wind speed is somewhat greater than the average as it is now measured. The gustiness at the location considered is influential here (Lettau and Haugen 1957). Since the power in the wind is a function of the wind speed cubed, an average wind speed does not give the true value of the power in the wind. The reported hourly wind produces an underestimation of the power of the wind (JBF 1977a). According to studies by the Electrical Research Association in England during the 1950s, this underestimate is < 10% (Changery 1975).

The most useful coastal data for Wisconsin appear to be those of the Great Lakes Observing Program. Light stations and harbors along the coast of Lakes Superior and Michigan are the major locations of these wind observations. Many of these observations are, however, made only four times a day.

Electric utilities have meteorological monitoring programs on sites of proposed and operating power plants. Observations required by the

Department of Energy on proposed nuclear power plant sites are documented and available from Battelle Northwest Laboratories (Verholek 1977). Data from other sites are available from the electric utility companies.

There appears to be general agreement among students of wind energy applications, that the quality of these wind speed observations is only sufficient for an approximation of power output of wind machines.

WIND SPEED CHARACTERISTICS

Wind Speed Frequency and Duration Curves

In studying a wide range of wind speed observations from many sites, it is useful to distribute the observations into classes or categories and make speed-frequency histograms: wind speed in miles per hour or meters per second on the horizontal axis and the number of hours of each wind speed class on the vertical axis.

By summation of the data used for the histogram, a wind speed duration curve is obtained. This is the cumulative frequency curve with the duration of the wind speed $v \geq v_1$ on the horizontal axis in hours or percentage of the time period considered and the wind speed v_1 on the vertical axis.

The longer the time for which a particular wind speed blows, the flatter the duration curve is at that point. Very high and very low wind speeds generally blow a short period of time. The curves, therefore, have steep sections at either end. The extensive wind survey by the Electrical Research Association in England showed that sites with approximately the same average annual wind speed have wind speed duration curves of a similar shape (Golding and Stodhart 1952; Tagg 1957). This characteristic is used to estimate the energy output of wind machines by means of a relatively simple method (see sections 5 and 6).

Variation of Wind Speed with Height

The wind speed generally increases with height. The variation of the mean wind speed v with height z can be given by several analytical expressions (Lettau and Haugen 1957), of which the following are often used:

Simple Power Law: $v \sim z^{\alpha}$
Logarithmic Law: $v \sim \log (1 + z/z_0)$,

where α is a constant and z_0 is a length that is called the roughness parameter of the ground surface.

The exponent α depends on terrain features, atmospheric stability, distance from the ground, and the speed of the overall air flow. The value of α varies between 0.05 and 0.5 (Reed 1975; Lettau and Haugen 1957). Lettau found during the Great Plains Turbulence Field Program in the lowest 10 m over open prairie country for typical conditions during daytime α = 0.11 to 0.13, nighttime α = 0.31 to 0.38, and in a neutral case α = 0.14 to 0.16. The same author suggests that for estimates, the value of α = 1/5 during nighttime and α = 1/7 during daytime may be used (Dr. H. H. Lettau 1978: personal communication). Takle and Brown (1976) found values of o approximately between 0.1 and 0.14 during daytime and 0.24 and 0.26 during nighttime for Ames, Iowa, using five levels on a tower: 2, 4, 8, 16, and 32 m. These authors found a dependency of γ and the observation heights by calculating α for three combinations of levels: α = 0.14 for levels 2 to 16 m, α = 0.18 for 2 to 32 m, α = 0.28 for 16 to 32 m. Since most NCC land wind speed observations are taken at about 6 to 7 m above the ground, the lower values of α seem more appropriate when NCC data are employed.

The aerodynamic roughness parameter z_o in the logarithmic law varies dramatically with the type of surface and to a lesser extent with the time of year. Roughness is higher during the summer than during the winter (Kung and Lettau 1961). The employment of the simple power law and the logarithmic law for airport aerodynamic roughness conditions results in approximately the same wind speed height adjustment.

Justus and Mikhail (1976) and Reed (1975) describe formulas for the simple power law α that take into account both the observed wind speed and the observation height.

An extensive evaluation of the utility of the 1/7-power law has been performed by Reed (1976a and 1976b), employing data from meteorological research towers as well as long-term records from regular weather stations. He concludes that since the wind machines operate at relatively high wind speeds, the 1/7-power law is a satisfactory approximation of the wind speed increase with height over flat terrain such as airport sites. In addition, he also found a close similarity between the 1/7-power law and the logarithmic model with a 0.03 m roughness factor. It appears, therefore, that the use of the simple power law with an exponent value of 1/7 is accceptable for the wind energy analysis of this study.

Seasonal and Diurnal Variation of Wind Speed

Phillips and McCulloch (1972) report on the climate of the Great Lakes Basin:

> There is a greater tendency for winds to have a westerly component in winter. In January over the middle and upper lakes regions, winds blow from the west and northwest 40 to 50% of the time, with northwest winds prevailing. South of the lakes, winds from the

west and southwest direction predominate 30 to 40% of the time. Wind speeds average between 6 and 19 mph.

Winds are generally strongest in early spring with mean speeds from all directions over 8 mph and highest mean speeds above 13 mph and usually from the prevailing direction. Stronger speeds are associated with increased cyclonic activity and less surface retardation since the ground is either snow covered or thawing and there is little vegetative growth.

In summer south winds prevail since the flow is often controlled by a high pressure area extending over the southeastern United Stated. In July the direction in the upper lakes is west and southwest about 40% of the time. Over the lower lakes, winds blow from the south and southwest more than half the time. Summer winds are generally more variable in direction and less variable in speed than winter winds.

Winds in October reflect the transition between summer and winter conditions in both speed and direction. The increase in cyclonic activity and the large thermal differences between air and water contribute to the high mean wind speed.

These regional and seasonal effects are, of course, modified by local influences. For example, a topographical ridge south of Sault Ste. Marie explains the predominance of easterly winds at the airport in all months. White River, situated in the valley, has calm conditions more than 30% of the time.

In the Great Lakes region, the wind usually reaches its maximum at about mid-afternoon, decreases near sunset, and remains low during the night until a few hours after sunrise (Asmussen et al. 1975; Takle and Brown 1976; Justus and Hargraves 1977). This diurnal variation tends to be less in the winter. In the summertime, particularly, solar radiation causes unstable conditions resulting in convection currents that interlock air flows at different heights and transfer energy from the higher levels to the lowest ones. Tagg (1957) and Lettau and Haugen (1957) refer to studies that indicate a minimum windspeed at about midday at the higher levels (> 150 m), with a well-defined maximum during the night. Two maxima are found at an intermediate level.

The height at which the reversal of the diurnal variation of wind speed takes place, appears to be a function of both the amount of surface heating and the wind speed. Takle and Brown (1976) find no reversal in Ames, Iowa, for heights up to 32 m. Land and sea breezes often occur at low level coastal sites, due to the more rapid temperature changes on land.

Measurements of wind direction and speed are needed to distinguish between the influence of solar radiation and land-sea interface upon the variation in wind speed. Asmussen et al. (1975) find approximately the same diurnal variations along Lake Michigan as Takle and Brown in Iowa. The variation in the wind from day to day is significant.

Asmussen et al. (1975), Malver (1976), and Justus and Hargraves (1977) in Michigan, Minnesota, and the Great Lakes region, respectively, find the same pattern of seasonal variation in the average wind speed, with roughly a 1 to 1.5 m/sec difference between the wind speed during early spring and summer at a given site.

Annual average wind speeds vary about 10% to 15% at a site. Malver (1976) for example, gives the annual average wind speed for four sites in Minnesota over a 10-yr time period. These data show that the variation in the annual average wind speed averaged over the four locations for a period of 10 yr is only about 4%. Thus, the diversity in the wind tends to cancel out differences between the four locations. This characteristic may be useful when considering the long-term performance of an array of interconnected wind machines.

The annual average wind speed tends to be relatively constant over a long period of time, as shown by Thomas (1945) for the New England area. Therefore, if a particular wind energy conversion system is suitable for a certain area using wind speed data of about 5 to 10 yr, one can assume this to be correct for a long period. A freak low month should be considered an emergency and dealt with accordingly.

The evidence found strongly suggests that wind is a constant and reliable power source, as long as the short-term variations within the month can be equalized.

Geographical Variations in Wind Speed

As indicated previously, the wind increases with height and during certain times of the year. Other factors influence the wind speed, particularly the existence of hills, ridges, large bodies of water, and surface roughness. Asmussen et al. (1975) report:

> The Great Lakes appear to have a profound effect on the winds in the region. At inland locations and sheltered meteorological stations along the coastlines, average annual wind speeds are in the 8 to 11 mph range. This corresponds to an average annual wind power density of 100 to 150 W/m^2 at 10 m. Since most of the meteorological stations are either inland or sheltered, any national wind power survey would rate the Great Lakes Region as only "moderate" as far as wind power is concerned. This is in fact the exact conclusion drawn by Reed (1975).
>
> Wind data from U.S. Coast Guard stations indicates that annual average wind speeds of between 13 and 18 mph are the norm at or near the Great Lakes shoreline. These winds correspond to an

average annual wind power density of 225-375 W/m^2 at 10 m. These wind power densities rank among the highest within the U.S. and demonstrate that the coastal region of Michigan is an excellent area for wind turbine applications.

Because of the prevailing northwesterly winds during the winter, the Wisconsin coast of Lake Superior might have equal wind speeds, and Lake Michigan slightly lower wind speeds than the Asmussen data indicate. The data from the Great Lakes Observing Program should be useful for evaluating these wind patterns. These data show that it will be advantageous to site wind-driven generators along the coast of Lake Superior from a wind availability point of view.

The extensive wind survey by the Electrical Research Association in England not only found similar results to those quoted from Asmussen, but also that typical good hillsites show annual average wind speeds 35 to 100% higher than the measuring stations at lowland locations. It was found that the best site is a slope about 1:3.5 (16°) in the final few hundred meters from the nonflat top. Conical shaped hills are preferred to ridges, although those ridges that are perpendicular to the prevailing wind and have sides shaped similar to conical hills are favorable sites too (Golding and Stodhart 1952; Tagg 1957; Stodhart 1975). The wind flow over hills and ridges is accelerated or slowed down depending upon the form of the hill and ridge, the height and the location of the observation (Frost 1975).

As indicated, siting windmills in nonflat areas has to be done with extreme care. Frost suggests that peak winds occur at approximately half a hill height above the top of the hill and that the magnitude of these winds equals the wind speeds at three hill heights over level ground. However, results from the English survey indicate a reduction but no reversal of the vertical wind gradient for most of the investigated hills (Tagg 1957; Stodhard 1975). In Wisconsin the hills and ridges will be suitable sites for wind machines from an energy point of view. There are at least 1,400 drumlins that range in height from 7 to 40 m (average 15 m) that could be used in a similar way (Smith 1976). It is clear that the increase of the wind speed with height near hills, ridges, and drumlins will strongly depend on local circumstances.

The ground roughness has a significant effect on the vertical distribution of wind speeds. Kung and Lettau (1961) report aerodynamic roughness parameters and their seasonal variations for the region of the state of Wisconsin. These parameters are estimated by employing data on the area distribution of defined types of plant cover and an empirical numerical relationship between plant height and the aerodynamic roughness parameter. Roughness is found to be high during the summer, and higher in the northern section of the state than in the southern part, mainly because of the difference in land covered by forest.

Finally, the major conclusions of the wind survey for the selection and characteristics of windpower sites in England (Golding and Stodhart 1952) were:

(1) Meteorological isovent maps form a useful guide in the selection of windy sites.

(2) In many regions sites can be found where the average wind speed is 50% to 100% higher than the surroundings.

(3) Distance of the most promising hills to the sea is < 3.2 km (2 miles).

(4) Conical hills and ridges athwart the prevailing wind are about equally good.

(5) Altitude of a hill is not in itself a reliable criterion. Hills of only a few hundred feet are often as good as those exceeding 305 m (1,000 ft).

(6) After sufficient experience, the average wind speed can be estimated from site inspection with fair accuracy. But maps are not sufficient, and the hill must be climbed.

From the study of wind characteristics, it becomes clear that a wind availability survey on a detailed level has to be undertaken to get an accurate estimate of wind power. The experience gained from the survey of the English researchers can serve as a very useful guide. Unfortunately, this study has to rely on less accurate wind data.

Statistical Representation of Wind Speed Characteristics

A large number of wind speed data must be handled and evaluated for a study of the potential of regional wind energy conversion systems. For certain studies, it will therefore be helpful to find a statistical description of wind speed characteristics. Once this description is determined, its parameters can be compared between sites and/or times, and calculations can be made with mathematical formulae rather than going back to the raw data each time.

Wind distribution curves are skewed and vary between wind speed $v = 0$ and a large value. Two statistical functions with two parameters have been evaluated, the Weibull and the log-normal, of which the Weibull distribution function proved to be superior to the log-normal for wind speed distribution data (Justus 1976; Takle and Brown 1976). Although the Weibull function has a third parameter, the so-called location or zero-offset factor, both studies found that the two-parameter Weibull function is adequate since the very low wind speeds are of no interest for a wind energy study.

Although a statistical description of the wind speed or wind power characteristics can be useful for certain evaluations of WECS, the original time series of wind speed observations are preferred for the study of WECS-utility applications, whereby hour-by-hour electric load and wind speed data are employed.

WIND POWER CHARACTERISTICS

The Law of the Cube

The power in the wind of a free-flowing stream of cross-sectional area A is equal to the product of the kinetic energy per unit mass of moving air ($1/2\ v^2$) and the mass flow rate through A (pAv) so that the power in the wind

$$P_{wind} = \tfrac{1}{2} \cdot v^2 \cdot (p \cdot A \cdot v) = \tfrac{1}{2} \cdot p \cdot A \cdot v^3 \text{ W} \qquad (1)$$

where v = wind speed and p = air density. Only part of this power in the wind can be extracted (see the discussion on the efficiency of power extraction in Section 5).

The wind power density is given by

$$P_{w,d} = \frac{P}{A} = \frac{p \cdot v^3}{2} \text{ W/m}^2 \qquad (2)$$

with a standard sea-level air density of 1.2 kg/m^3 (dry air varies between 1.16 kg/m^3 at 30° C and 1.40 kg/m^3 at -20° C) (see also Justus and Hargraves 1977).

$$P_{w,d} = 0.61 \cdot v^3 \text{ Wm}^{-2}, \text{ v in m/sec} \qquad (2a)$$

$$= 0.054 \cdot v^3 \text{ Wm}^{-2} \quad \text{v in mph} \qquad (2b)$$

$$= 0.083 \cdot v^3 \text{ Wm}^{-2} \quad \text{v in knots} \qquad (2c)$$

This third power of the wind speed explains the need for wind speed distribution curves, since the power in the mean wind v is significantly lower than the mean of the power in the wind P_w, e.g.,

(1) For average wind speed = 6 m/sec: power density = 130 w/m^2

(2) For wind speed of 8 m/sec half the time and 4 m/sec half the time ($\overline{v}$ = 6 m/sec) gives an average power density of 173 W/m^2.

The ratio between the mean power in the wind and the power in the mean wind is called the energy pattern factor f, e.g.,

$$f = \frac{173}{130} = 1.33$$

Variations in Wind Power

Since the power in the wind varies with the third power of the wind speed, wind power is very sensitive to a change in the wind speed. For example, if the wind speed at a certain height above a conical hill is twice the wind speed in the surrounding flat lands, the power on top of that hill is eight times as high. This indicates that sites with good wind characteristics are highly desirable, but also, that the accuracy of the wind speed observations is extremely important.

SECTION 4

WIND CHARACTERISTICS IN WISCONSIN AND SECTIONS OF THE SURROUNDING STATES

WIND DATA EMPLOYED

Wind speed data of 12 major weather stations as well as five Coast Guard stations were analyzed (Figure 1).

Of these 12 weather stations, five are located in Wisconsin and seven in adjacent states. Time series of 3-h data for the period 1969-74 are analyzed. For the weather stations mentioned, < 0.05% of the observations are missing. Where necessary, interpolation has been used to fill in data points. After initial evaluation, Wausau, Grantsberg, Lone Rock and Camp Douglas in Wisconsin, St. Cloud in Minnesota, and Dubuque in Iowa were rejected for this study because (1) a complete time series for the period of 1969-74 is not available, and/or (2) too many data points are missing.

The observations of the wind speed, averaged > 1 min/h, are made at a height of approximately 7 m (20 ft) and recorded in whole knots. Presumably, rounding inaccuracies to the nearest integer value will average out. However, a systematic preference towards certain integer wind speed values is found in the data used for this study and others (Tagg 1957; Takle and Brown 1976).

The wind speed observations at the Coast Guard stations generally are made four to eight times a day and are available on microfiche. Data obtained cover the period 1970-74, although several months of data are missing for some stations. Following is a short description of the sites as obtained during telephone conversations with Coast Guard officers:

(1) Devils Island, Lake Superior shore. Small flat island. Anemometer on far north tip of island, approximately 7 m (20 ft) aboveground. Open to all sides.

(2) Eagle Harbor, Lake Superior shore. Anemometer approximately 20 m aboveground. Exposed to all sides but the south, where a mountain ridge blocks the southern winds.

(3) Plum Island, Wisconsin's Lake Michigan shore. Relatively flat island. Anemometer was most likely placed on a mast

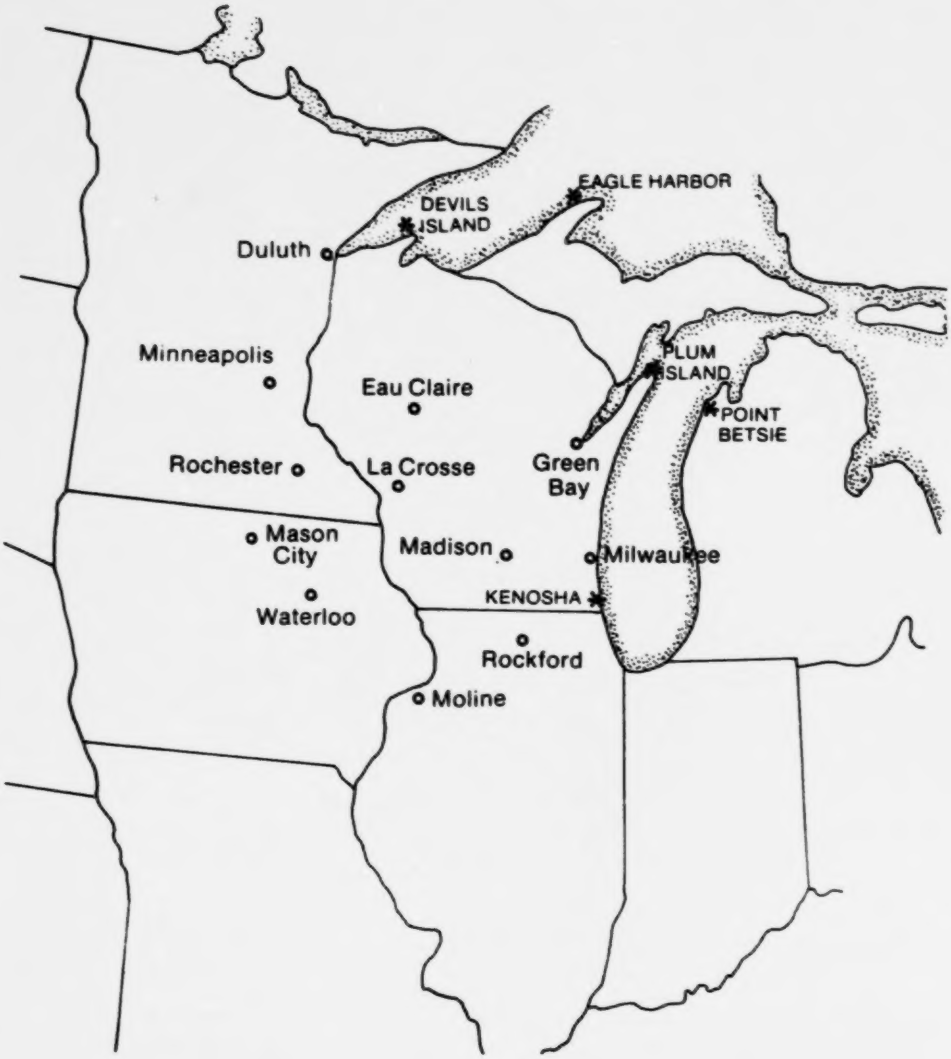
EAGLE HARBOR
DEVILS ISLAND
Duluth
Minneapolis
Eau Claire
PLUM ISLAND
POINT BETSIE
Rochester
La Crosse
Green Bay
Mason City
Madison
Milwaukee
KENOSHA
Waterloo
Rockford
Moline

Figure 1. Locations of airports (o) and Coast Guard stations (*).

approximately 15 m high, but this could not be further verified by the Coast Guard officer.

(4) Kenosha, Wisconsin's Lake Michigan shore. Anemometer approximately 25 m aboveground on top of hill. Open to all sides.

(5) Point Betsie, Michigan's Lake Michigan shore. Anemometer 17 m aboveground, open to all sides.

As is the case with the other data, integer values of the wind speed are recorded in knots.

Finally, the quality of these data is lower than those of the major weather bureaus. Data during the complete 1969-74 time period could not be obtained and as previously mentioned, many data are missing. Consequently, the results of the analysis of these Coast Guard stations are only useful to indicate the wind speeds that can be expected along the shores of Lakes Superior and Michigan. An analysis of WECS-utility application requires better data.

WIND SPEED CHARACTERISTICS

Table 1 displays for the major weather stations the annual average wind speed at four heights and the variation in the annual wind speed during the time period 1969-74. Note, that the 1/7-power law has been used to adjust the height. These stations can roughly be divided into 4 groups, with decreasing annual average wind speed: (1) Rochester, (2) Milwaukee, Mason City, and Waterloo, (3) Madison, Green Bay, Eau Claire, Duluth, Minneapolis, Rockford, Moline, and (4) La Crosse. The La Crosse airport is situated in the Mississippi Valley, which explains the low wind speeds observed. On the other hand, observations for Rochester are made on a ridge (Elliot 1977).

Figure 2 shows the seasonal variation in monthly average wind speeds for four representative sites: Rochester, Milwaukee, Eau Claire, and La Crosse. Maximum wind speeds generally occur during late winter and early spring; summer wind speeds are lower. Appendix A contains the monthly average wind speed at four heights for all 12 weather stations analyzed.

Figure 3 and the last two columns in Table 1 indicate that the annual wind speed varies between 2 and 14% around the mean. This is approximately the same as found by Malver (1976). Justus and Hargraves (1977) report slightly higher average wind speeds, which is most likely due to a different height adjustment procedure.

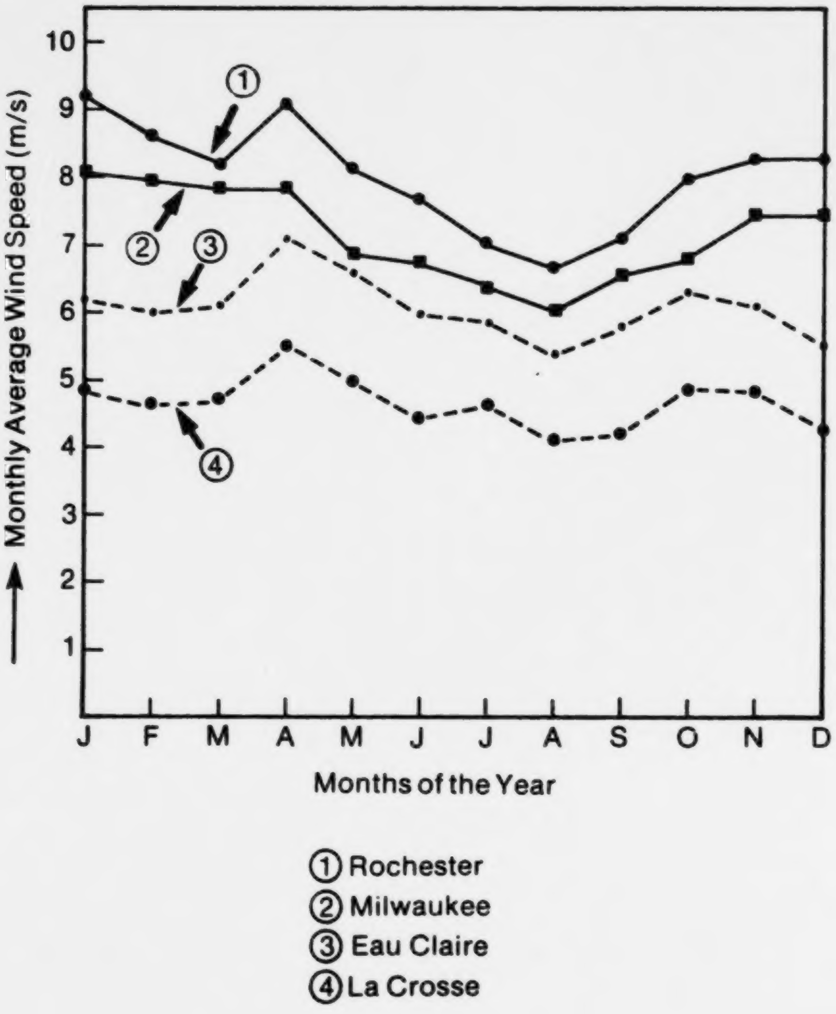

Figure 2. Monthly average wind speeds for four representative airport sites, 1969-74.

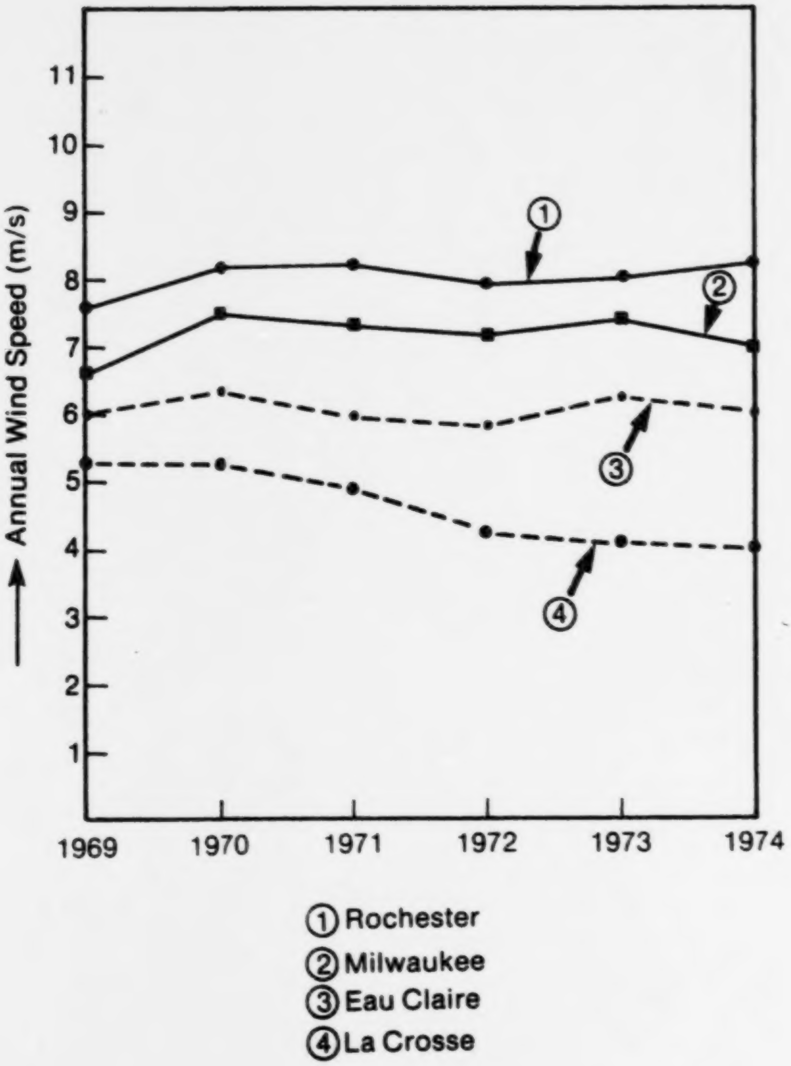

Figure 3. Annual wind speeds for four representative airport sites, 1969-74.

TABLE 1. ANNUAL 6-YR AVERAGE WIND SPEED (m/sec) FOR LOCATIONS IN AND AROUND THE STATE OF WISCONSIN. HEIGHT ADJUSTMENT WITH SIMPLE POWER LAW EXPONENT EQUAL TO 0.14. WIND SPEED OBSERVATIONS, 1969 TO 74, MADE AT A HEIGHT OF APPROXIMATELY 7 m.

	Annual average wind speed (m/sec)				Range around 6-yr mean value	
	Height aboveground (m)				(% of mean value)	
	7	20	30	60	-	+
Madison, Wis.	4.4	5.1	5.4	5.9	8	6
Milwaukee, Wis.	5.3	6.1	6.5	7.2	8	5
Green Bay, Wis.	4.6	5.3	5.7	6.2	4	3
Eau Claire, Wis.	4.5	5.2	5.5	6.1	4	4
La Crosse, Wis.	3.4	4.0	4.2	4.6	13	14
Duluth, Minn.	4.7	5.4	5.8	6.4	9	11
Minneapolis, Minn.	4.5	5.3	5.6	6.2	4	4
Rochester, Minn.	5.9	6.8	7.3	8.0	6	3
Mason City, Iowa	5.1	6.0	6.3	7.0	5	6
Waterloo, Iowa	5.1	6.0	6.3	7.0	10	9
Rockford, Ill.	4.6	5.4	5.7	6.3	4	4
Moline, Ill.	4.4	5.2	5.5	6.0	2	4

The diurnal variation of the wind speed will be further discussed in Sections 6 and 7. Wind speed duration curves are not presented, since it is felt that power output duration curves of a number of well-chosen wind machines are more useful (see Section 6 and Appendix D).

Figures 4 and 5 display the monthly average wind speeds and the annual wind speeds for the five Coast Guard stations. Note that the height is not adjusted to a reference height as previously done with the airport data. The simple power law for height adjustments is not accurate in the somewhat complex terrains of the Coast Guard statons. The seasonal variations of wind availability presented in Figure 4 are similar to those of the airport locations. The annual wind speed at Eagle Harbor on the shore of Lake Superior (Figure 5) is only slightly less than the one in Rochester, the best of the 12 airports evaluated (Table 1). Devils Island is comparable to Mason City, Rochester, and Milwaukee, the second best group of locations. Plum Island and Kenosha on the Wisconsin shore of Lake Michigan have wind characteristics similar to those at the airports in Madison, Eau Claire, and

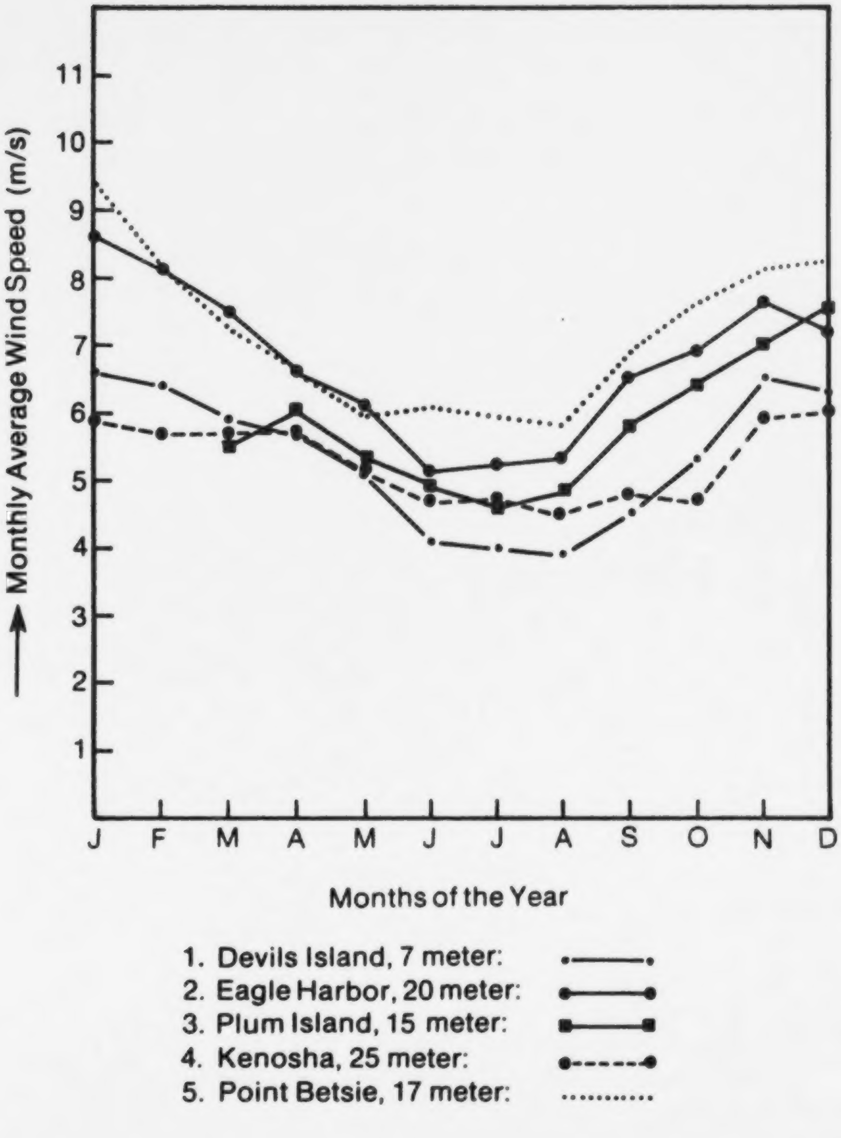

Figure 4. Monthly average wind speeds for five Coast Guard stations, 1970-74.

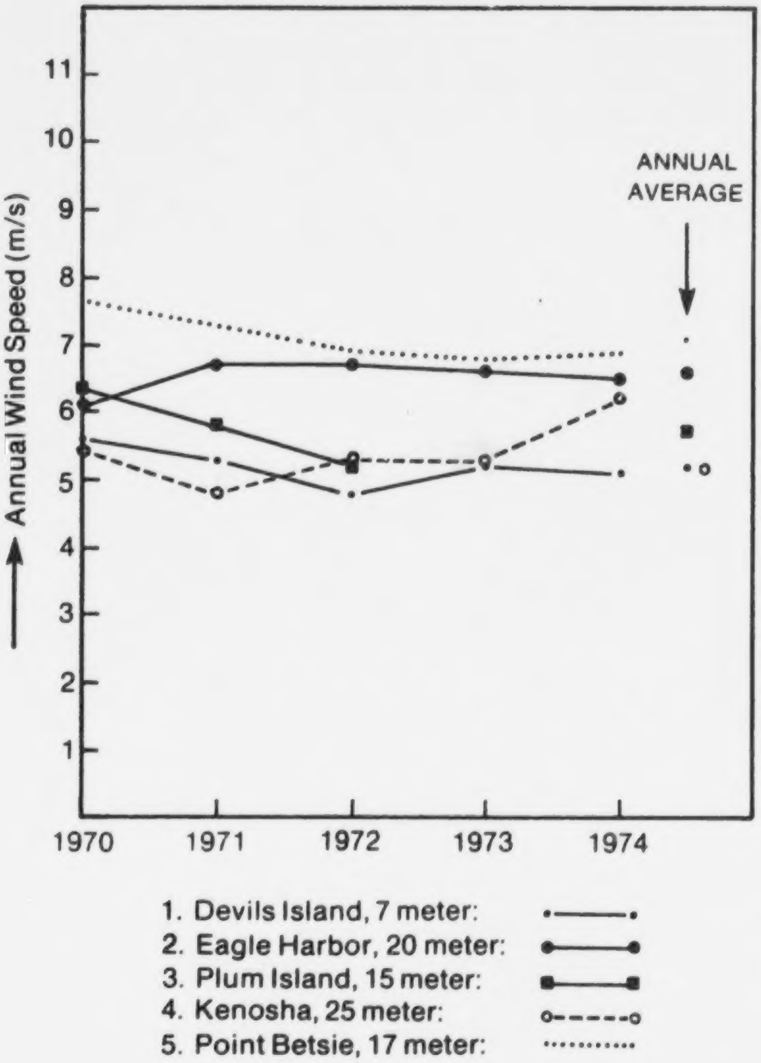

Figure 5. Annual wind speeds for five Coast Guard stations, 1970-74.

Minneapolis. Point Betsie on the Michigan shore of Lake Michigan is clearly superior to the other Coast Guard stations. The annual average wind power for the five Coast Guard stations can be estimated by using the data presented in Table 2 for those airport locations that have approximately the same annual wind speed.

WIND POWER CHARACTERISTICS

Table 2 displays for the 12 weather stations the annual average values of the wind power density for four heights and the variation in the annual wind power density figures during the time period 1969-74. Note that the differences between the stations and the four heights are larger for the wind power density than wind speed. This is due to the face that the power in the wind is proportional to the third power of the wind speed.

TABLE 2. ANNUAL 6-YR AVERAGE WIND POWER DENSITY (W/M^2) FOR LOCATIONS IN AND AROUND THE STATE OF WISCONSIN. HEIGHT ADJUSTMENT WITH SIMPLE POWER LAW EXPONENT EQUAL TO 0.14. WIND SPEED OBSERVATIONS, 1969 TO 74, MADE AT A HEIGHT OF APPROXIMATELY 7 m.

	Annual average wind power density (W/m^2)				Range around 6-yr mean value	
	Height aboveground (m)				(% of mean value)	
	7	20	30	60	−	+
Madison, Wis.	101	159	189	254	22	17
Milwaukee, Wis.	152	238	283	381	24	13
Green Bay, Wis.	111	174	207	279	8	6
Eau Claire, Wis.	106	166	197	266	11	16
La Crosse, Wis.	60	95	113	152	27	28
Duluth, Minn.	109	171	203	274	28	28
Minneapolis, Minn.	104	163	194	261	9	7
Rochester, Minn.	206	323	384	517	16	10
Mason City, Iowa	157	246	293	394	11	13
Waterloo, Iowa	153	239	285	383	21	19
Rockford, Ill.	116	182	216	291	16	11
Moline, Ill.	108	170	202	273	6	10

Figure 6 and Appendix B show the seasonal variation of the wind power density.

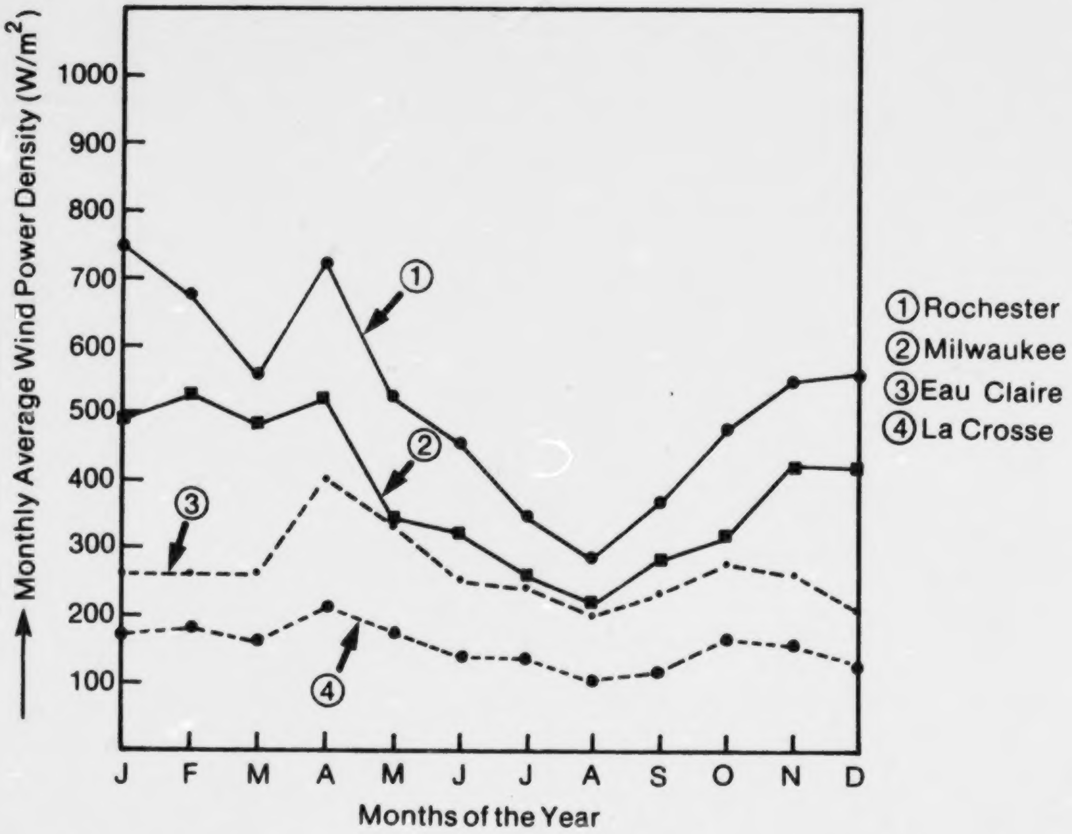

Figure 6. Monthly average wind power density for four representative airport sites, 1969-74.

CONCLUDING REMARKS

Comparison of wind speed and wind power density values for the region considered here and for other parts of the United States indicates that this region has a moderate to good potential for WECS applications (Coty 1976). It should be kept in mind that these values are obtained by employing data that are not necessarily typical for the best nearby wind power locations. Secondly, the 1/7-power law has been used for height adjustments, which will somewhat underestimate the wind speed at higher elevations during nighttime. Finally, data from La Crosse and Rochester show the importance of local terrain features: a factor 3.4 difference in average power.

SECTION 5

WIND MACHINES: LITERATURE REVIEW

Wind machines have many different forms and all are more or less capable of capturing a fraction of the power in the wind. Basically, they can be divided into the horizontal and vertical axis machines. Eldridge (1975) gives a clear overview of the taxonomy of wind machines.

EFFICIENCY OF POWER EXTRACTION

The power coefficient c_p is defined as:

$$c_p = \frac{\text{power output from machine rotor}}{\frac{1}{2} \cdot \rho \cdot A , v^3} \qquad (3)$$

where v is the intial wind speed. Betz (1959) calculated that the maximum power density that can be extracted from a free-flowing wind stream is 16/27 of the power in the wind:

$$c_{p_{Betz}} = 16/27 = 0.593 \text{ (see Appendix F).}$$

The power coefficient of the wind machine rotor varies with the ratio of the tip speed to the speed of the wind stream. Figure 7 displays power coefficients for several machines as a function of the blade tip speed to wind speed ratio (Eldridge 1975). This shows that the high speed two (or three) blade and Darreus types are the most efficient machines. It should be emphasized that this discussion deals only with the rotor of the machine. Additional power losses occur with gearing, electricity generation, and storage devices, etc.

OPERATING CHARACTERISTICS OF WIND MACHINES

Following is a description of wind machine operating characteristics pertinent to this study. For detailed technical information see Wilson et al. (1976), Wiesner and Kisovec (1976), JBF (1977b), or Cromack and Lefebvre (1977).

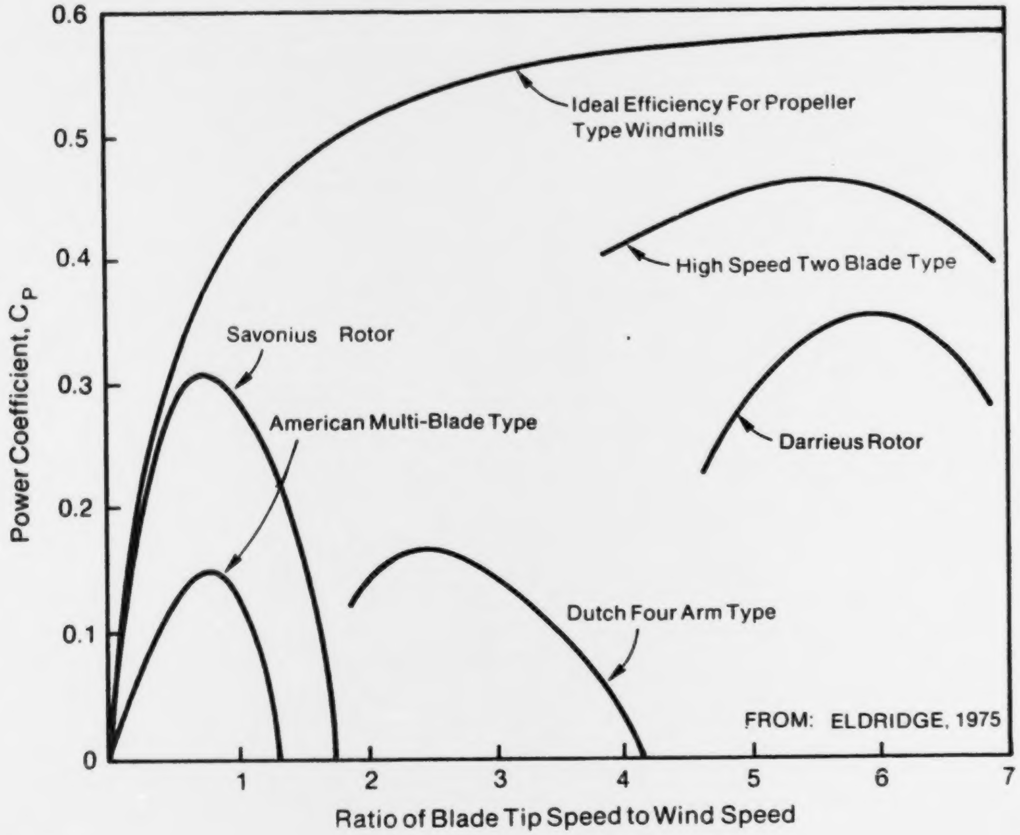

Figure 7. Typical performances of wind machines (Eldridge 1975).

As displayed in Figure 7, the power coefficient of a wind machine varies with the tip speed ratio. In order to extract the maximum amount of power out of the wind, the rotor has to turn at a variable speed to maintain the optimal tip speed ratio. This type of arrangement requires a variable speed constant frequency generating system, if the wind machine is to be connected with an electric utility grid. For those applications of WECS where constant frequency is of no concern, a variable speed rotor may be desirable.

Many of the modern wind machines are designed to operate with a constant rotational speed. As Eldridge (1975) states:

> In other cases, such as the initial ERDA-NASA 100kW wind machine, power output at wind speeds greater than its rated value of 18 mph has been sacrificed to simplify system design. For a power coefficient, C_p, of 0.35, this machine has a theoretical maximum power output as shown by the dotted line in the diagram (Figure 8) and would reach an output of 4,935 kW at wind speeds of 60 mph. However, a synchronous ac generator with a fixed-ratio gear train has been chosen for this design which must be operated at constant input speed, i.e., fixed wind rotor speed. Aside from friction losses, the theoretical maximum power output is maintained between the designed cut-in wind speed of 8 mph and the rated wind speed (v_r) of 18 mph by varying the output load on the system to maintain a constant rotor speed of 40 rpm. For wind speeds above 18 mph the rotor speed is maintained at 40 rpm by varying the pitch of the rotor blades. In this manner a constant power output of 100 kW is maintained between the rated wind speed of 18 mph and the cut-off wind speed of 60 mph, at which point the rotor blades are feathered to protect the machine in high winds. This type of design does not result in large losses of available wind power since, e.g., when the average wind speeds are about 12 mph, the annual energy content of the wind is low for wind speeds below 8 mph and above 30 or 40 mph.

By limiting the power output to the rated value of 100 kW, the size and cost of the generating system has been significantly reduced, with some loss of available wind power. Sulzer (1976) suggests that even with high values of v_r it is often cheaper to build a slightly larger constant speed rotor than the smaller variable rotor to obtain the same amount of energy. In this study, only wind machines with constant speed rotors were considered.

Associated with the rated wind speed is the rated power density P_{rd}: the rated power divided by the total swept area of the blades (W/m^2). Given a certain rated power output or capacity, a large rotor (low-rated power density) will reach its rated capacity at a relatively low wind speed. Such a wind machine with a low rated power density is therefore effective at relatively low wind speeds, but wastes a fraction of the energy in the high winds. Small rotors (high P_{rd}) will reach that same capacity at a relatively high wind speed and are therefore better in a high wind regime.

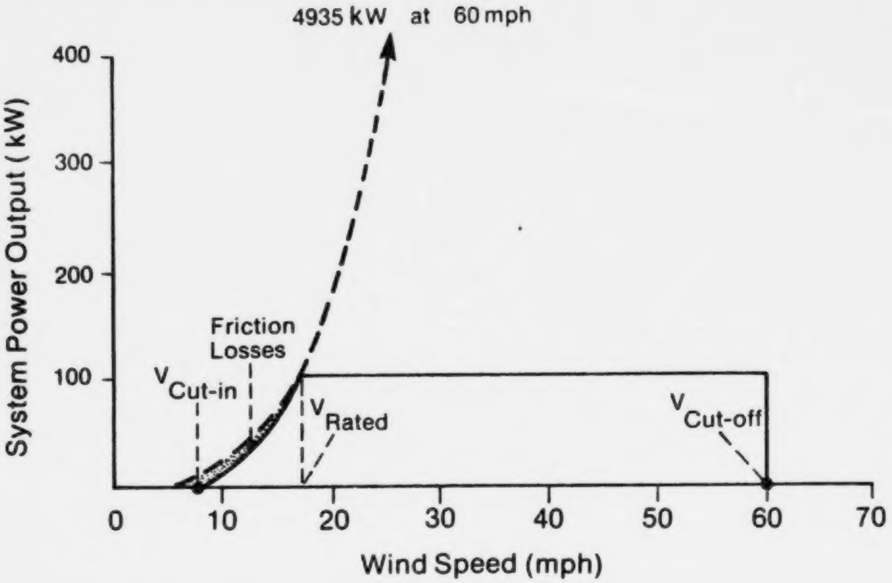

Figure 8. Power output of 125 ft (38 m) diameter rotor, rated at 100 kW in winds of over 18 mph (8 m/sec) (Eldridge 1975).

A rated power density of about 100 to 200 W/m^2 apears to be suitable for the wind regime of Wisconsin (Wiesner and Kisovec 1976; JBF 1977a).

SPECIFIC ENERGY OUTPUT AND CAPACITY FACTORS

The capacity factor F_p of a wind machine is defined as for the other types of electric generation plants:

$$F_p = \frac{\overline{P}}{P_r} \tag{4}$$

where P = average power output for a given period and P_r = rated power output. The specific energy output E_s for a given period of H hours is given by:

$$E_s = H \times \frac{P}{P_r} = H \times F_p \text{ (kWh/kW/time period).} \tag{5}$$

Generally, the annual specific energy output is considered, so that H = 8,766 h. As can be seen in Eq. (5), the E_s is the energy obtained during a certain time period per installed kilowatt of capacity. Reduction of the rated wind speed increases both the F_p and E_s. But, at a given capacity P_r, lowering the v_r means increasing the cost of construction (longer blades) and losing some power in the high winds. An economic analysis takes these factors into account.

The average power density $\overline{P}_d$ for a given time period is given by:

$$\overline{P}_d = \frac{\overline{P}}{A} = \frac{\overline{P}}{P_r} \cdot \frac{\overline{P}_r}{A} = F_p \cdot P_{rd} \text{ (W/m}^2\text{).} \tag{6}$$

Figure 9 displays the parametric variation of P_d versus v_r for three wind regimes (Zimmer et al. 1975). As can be seen, the P_d increases significantly in the high wind regime with increasing v_r, but not as fast as P_{rd}. This results in a lower F_p and E_s. P_d hardly increases in the lower wind regimes, which also results into lower F_p and E_s. The same authors show that the influence of the cut-in wind speed v_o on F_p (and thus E_s) is small in comparison to the influence of the choice of v_r.

Zimmer et al. (1975) report annual capacity factors between 0.4 and 0.5 for a wind machine with a P_{rd} = 100 W/m^2 at a height of 30 m for several Upper Midwest locations. These factors increase to between 0.55 and 0.65 at a height of about 60 m. Seasonal plant factors vary as much as ± 20% from the annual values.

Golding and Stodhart (1952), Tagg (1957), and later Justus et al. (1976) indicate an important estimation method for E_s. These authors find a

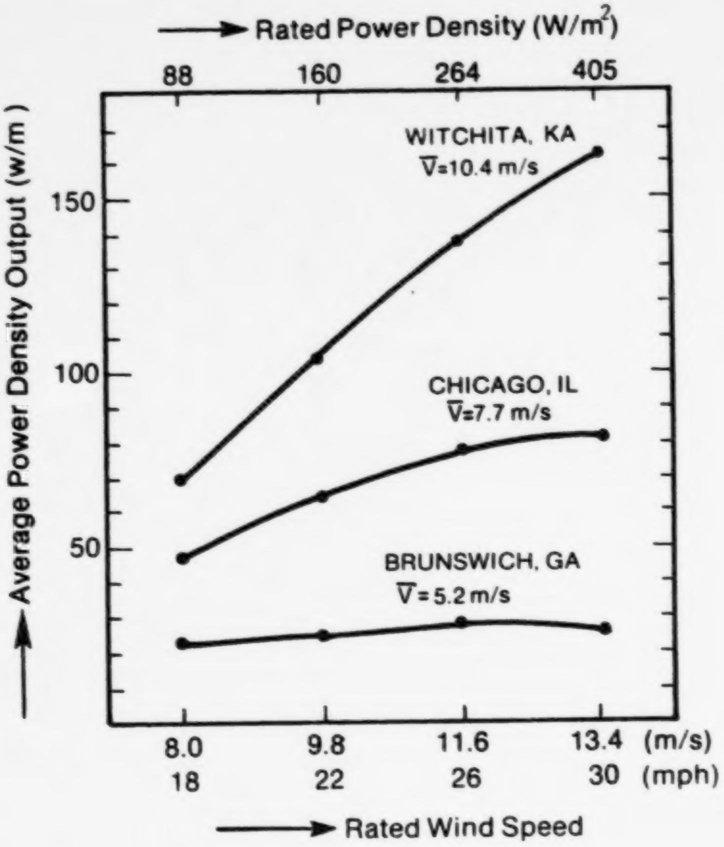

Figure 9. Average power density output of wind machines as a function of the rated power density (or rated wind speed) for three cities with different average annual wind speeds at height of 61 m (200 ft) (Zimmer et al. 1975).

clear relation between E_s and the average annual wind speed at a given location and for a given wind machine (Figure 10). Once these curves are made for a machine, only the average wind speed at a location is needed to get a rough estimate of the annual wind energy obtained. Because the influence of the cut-in wind speed v_o on E_s and F_p is small in comparison to the choice of the rated wind speed, the wind machines are mainly characterized by the rated power density P_{rd}. It appears that many machines can be evaluated by constructing curves as in Figure 10 for a range of values of P_{rd}.

POWER DURATION CURVES OF WIND MACHINES

The power output of a wind machine can also be presented in a curve giving an indication of the number of hours during a given time period that a certain power output level is equaled or exceeded. A wind machine with a low rated power density reaches the rated power level more often than a high rated power density machine.

Molly (1976) presents the effects of the choice of the rated power density in an interesting way. Figure 11 shows mean power output and power duration curves for three machines with rated power densities of 100 W/m^2, 300 W/m^2, and 500 W/m^2. The mean output per unit of swept area is the highest for the wind machine with a rated power density of 500/m^2. However, the capacity factor, the specific energy output, and the time that the rated power output is reached are high for the 100 W/m^2 machine and low for the 500 W/m^2 machine: (Wind regime with annual average wind speed of 6.7 m/sec at 10 m).

Wind machine rated power density (W/m^2)	Capacity factor	Specific energy output (kWh/kW/yr)	% time rated power reached
100	0.70	6,140	45
300	0.47	4,120	18
500	0.36	3,160	8

Data presented in the next section display similar variations in these parameters for the region considered.

SITING OF WIND MACHINES

Summary conclusions of the extensive wind survey made in England for good wind power sites were discussed in Section 3 (Golding and Stodhart 1952).

Recently the American Wind Energy Association (1977) reported on a survey of historical and current site selection techniques for the placement

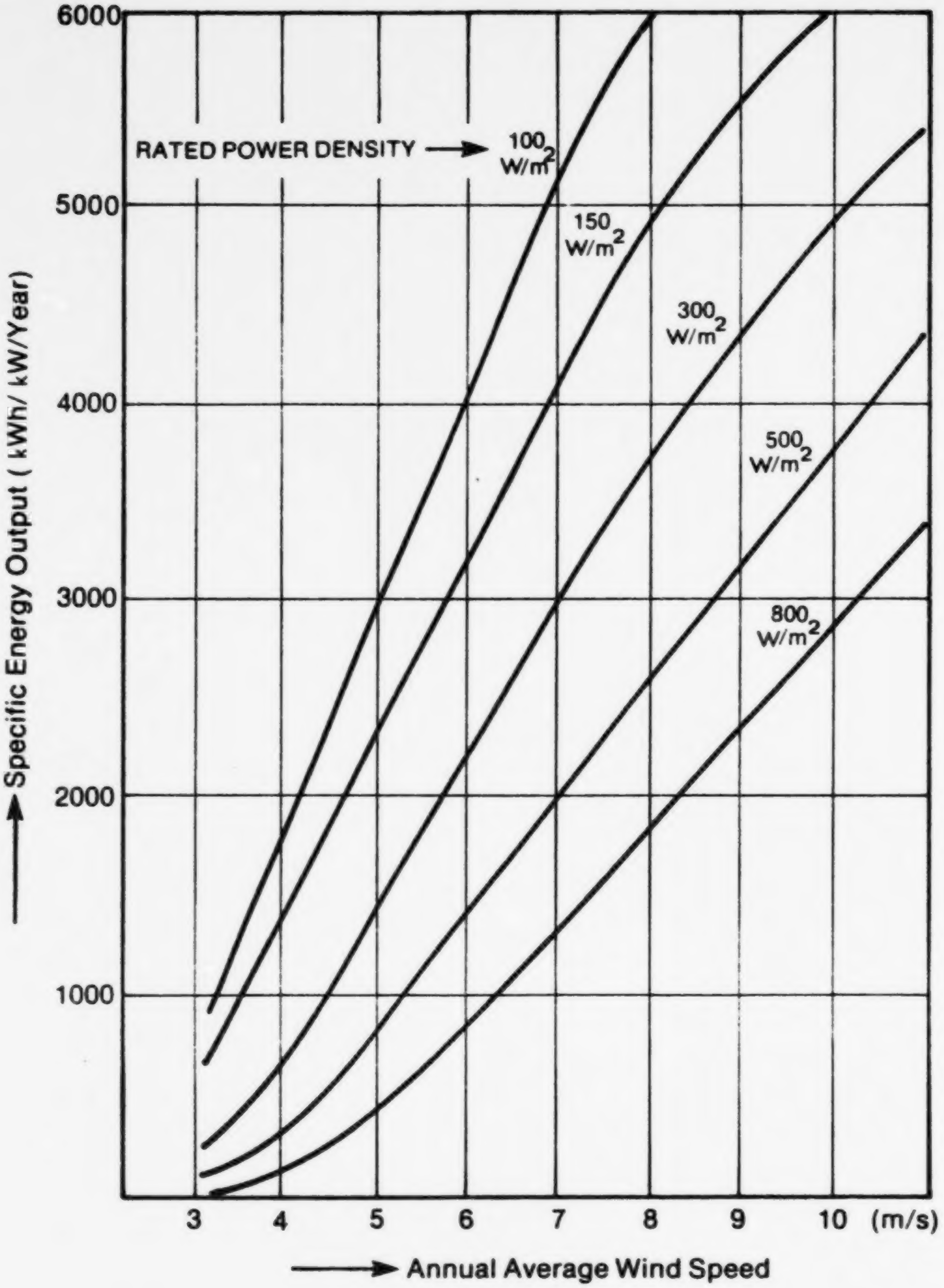

Figure 10. Specific energy output as a function of annual average wind speed and rated power density of the wind machine (Tagg 1957; Justus et al. 1976).

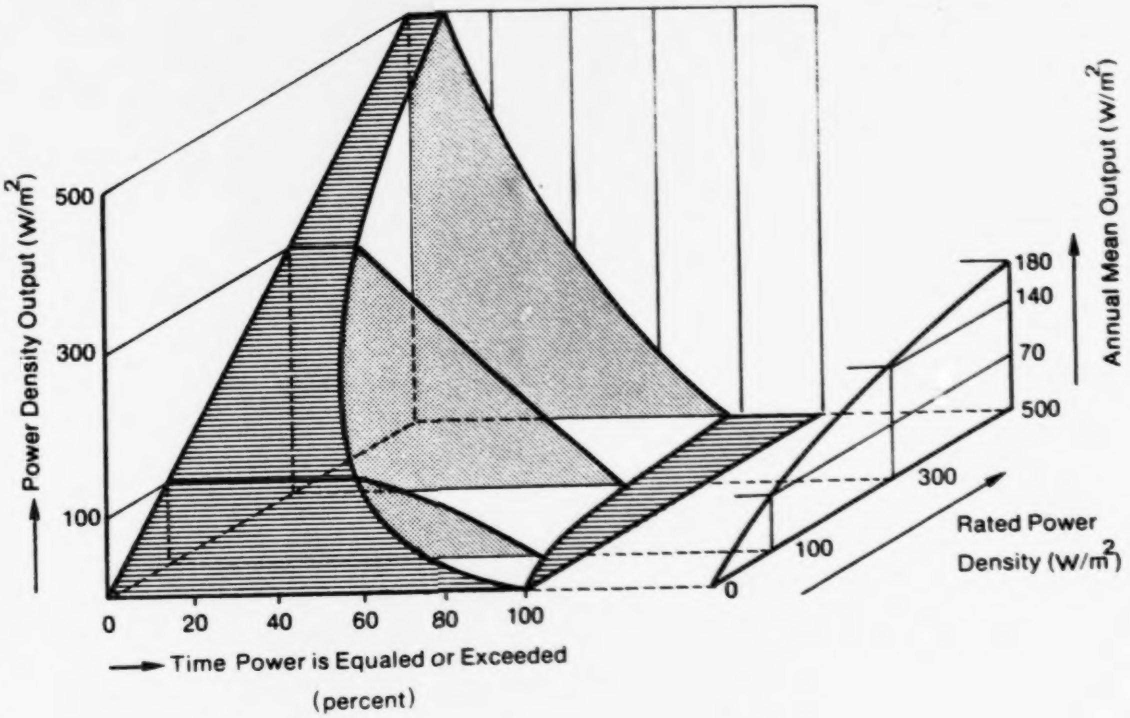

Figure 11. Effects of the rated power density of wind machines on the power output duration curve and the annual average power output for a location with annual average wind spped of 6.7 m/sec at 10 m height. Hub height wind machines is 72 m (Molly 1976).

of small energy conversion systems. This study has been conducted through questionnaires, interviews, and a literature search. The major findings of this study were:

(1) The primary factor in selecting the location for a WECS on a given site was the application of the power. Water pumping machines are constrained by the availability of water, and electric generating machines constrained by the location of the batteries. This was amplified by the fact that most wind electric systems prior to 1945 were low voltage (32 vdc), high amperage machines require heavy gauge wire.

(2) When meteorological factors affected the selection of machine location or tower height, such factors were dealt with on a basis of intuitive understanding gained from years of experiences, as well as general guidelines supplied by WECS manufacturers.

(3) With the location of the machine determined by the application of the power, the next factor in the siting process was the selection of tower height. System distributors indicate that tower height decisions were often made on the basis of tower cost, while machine owners indicate that tower height was selected to clear obstructions.

(4) In the application of wind energy to pumping water, some issues that affected site selection and tower height were nonmeteorological. Among these were the fact that the tower was used to facilitate the drilling and casing process, and in the presence of abundant water, the WECS were moved to sites the rancher or farmer wanted grazed.

(5) The widely applied rule of thumb for selecting tower height was that the tower be 4.6 to 7.6 m (15 to 25 ft) above obstructions within a 91 to 152 m (300 to 500 ft) radius. The owner's manuals of the period state that dissatisfaction with performance is primarily the result of improper siting.

(6) While approximately 95% of those responding used wind machines for water pumping, nearly 75% of those responding indicating they would like to use wind energy for electrical applications in the future.

(7) The most often cited source of information on site selection was the WECS salesman or dealer (53%).

(8) Questionnaire responses most often cited the National Weather Service (NWS) (35%) as the source of information on wind data they would use. It is unclear if those responding to the questionnaire know how to get data from NWS, what type of data to request, or what to do with it once obtained.

(9) Current dealers are using low cost wind-run, and recording anemometers to assist in site selection.

Most wind measurement field programs related to wind energy resource utilization have been quite general in nature or focused on the smallest time and space scale to help the design of hardware (Orgill 1977; Ramsdell 1977). Some programs presently collect detailed data on sites that may be used for WECS-utility applications (Hewson et al. 1975, 1976; Ramage et al. 1977; Lindley and Melton 1977; Ramsdell 1977).

OVERVIEW OF WIND MACHINES: OPERATING OR IN DESIGN STAGE

Table 3 shows an overview of wind machines from many different companies. Several presently operating machines with a capacity smaller than 6 kW are not shown (the table is not meant to be complete). As displayed, the rated power density P_{rd} varies between 100 and 600 W/m^2. Not all the necessary data for each machine have been obtained, and some of the data are rough estimates.

Table 3. CHARACTERISTICS OF WIND MACHINES PRESENTLY OPERATING OR IN THE DESIGN STAGE

Manufacturer	Rated power (kW)	Rated wind speed (m/sec)	Diameter (m)	Swept area (m^2)	Rated power density (W/m^2)
Aeropower	1.0	8.9	3.	7.3	137
Aerowatt	4.1	7.1	9.4	68.8	60
American Wind Turbine	1.0	8.9	3.7	10.5	95
Amerenalt	1.5	12.5	2.4	4.7	319
	2.5	17.0	2/4	4.7	532
DAF Darrieus	14.0	13.4	6.1	?	?
Dunlite	2.0	11.2	4.1	13.3	150
	2.0	13.4	3.0	7.3	274
Electro	6.0	11.6	5.0	19.6	306
Kedco	1.2	9.8	3.7	10.5	114
	2.0	11.6	3.7	10.5	190
	1.2	7.6	4.9	18.7	64
	2.0	9.8	4.9	18.7	107
Millville	10.0	11.2	7.6	45.6	219
North Wind Eagles	2.0	9.8	4.4	15.3	131
	3.0	12.0	4.4	15.3	196
Pinson Cycloturbine	2.0	10.7	3.7	?	?
Schachle	140.0	11.6	22.0	378.0	370
Sencenbaugh	0.5	10.7	1.8	2.6	192
	1.0	10.3	3.7	10.5	95
Windstream 25	15.0	11.6	7.6	45.6	329
Wind Wizard	0.6	11.6	2.7	5.9	102
WTG Systems	200.0	13.4	24.4	467.0	428
Wincharger	0.2	10.3	1.8	2.6	77
Zephyr	15.0	13.4	6.1	29.2	513
Heronymus' Wind Furnace	25.0	11.7	10.0	77.0	325
WESCO, England	155.0	13.4	18.3	263	590
NOAH, W. Germany	15.0		12.0	113	132
	30.0	10.0	12.0	113	265
	45.0		16.0	201	224
Gedser, Denmark	200.0	15.0	24.0	450	440
Tvind, Denmark	2000.0	15.0	54.0	2286	875
SAAB, Sweden	75.0	10.0	18.0	254	295
ERDA/NASA-MOD-0	100.0	8.0	38.0	1072	93
ERDA/NASA-MOD-0A	200.0	10.7	38.0	1072	186
Boeing*	1125.0	10.4	81.0	5128	220
Kaman*	500.0	11.7	46.0	1640	305
MOD-1*	2000.0	14.4	61.0	2918	685
MOD-2*	2500.0	5.4	91.0	6566	380

Source: The compilation of small wind machines is largely based on the Wind Power Access Catalog, No. 1, published in Wind Power Digest, Fall 1977. Some machines have been added to this list by the author.

*Machines in design stage.

SECTION 6

POWER OUTPUT OF A SELECTED NUMBER OF WIND MACHINES IN WISCONSIN AND SECTIONS OF THE SURROUNDING STATES

CHARACTERISTICS OF THE SELECTED WIND MACHINES

The major parameter that characterizes a wind machine is the rated power density. The rated power densities employed in this study are presented in Table 4. The power output as a function of the wind speed is assumed to be the same as shown in Figure 8 for the constant speed rotors. The curve between the cut-in and rated wind speed is approximated by a quadratic function. The rated power densities chosen are generally considered suitable for the north-central region of the United States.

TABLE 4. CHARACTERISTICS OF THREE SELECTED WIND MACHINES

	Rated power density (W/m^2)		
	90	220	305
Cut-in wind speed (m/sec)	3.6	4.2	5.1
Rated wind speed (m/sec)	8.0	10.4	11.7
Cut-out wind speed (m/sec)	26.0	26.0	26.0
Example of wind machine	NASA/DOE 100 kW	Boeing 1125 kW	Kaman 500 kW

SPECIFIC ENERGY OUTPUT AND CAPACITY FACTORS

Table 5 displays the annual average capacity factors for the three wind machines chosen at all 12 major weather stations. The variation in these factors is roughly a factor of two, both between the locations and the wind machines at a height of 60 m. Note that the wind speeds at airports adjusted to 60 m may approximate wind speeds at lower elevations for more favorable nearby locations. Zimmer et al. (1975) and Justus and Hargraves (1977) find slightly higher capacity factors.

TABLE 5. ANNUAL AVERAGE CAPACITY FACTORS FOR THE THREE SELECTED WIND MACHINES AT 12 AIRPORT LOCATIONS, THREE HEIGHTS. HEIGHT ADJUSTMENT WITH SIMPLE POWER LAW EXPONENT EQUAL TO 0.14. DATA AVERAGED OVER 6 YR, 1969-74.

	Rated power density								
	90 W/m^2			220 W/m^2			305 W/m^2		
	20m	30m	60m	20m	30m	60m	20m	30m	60m
Madison, Wis.	0.35	0.39	0.45	0.19	0.22	0.28	0.13	0.15	0.21
Milwaukee, Wis.	0.47	0.50	0.59	0.28	0.32	0.39	0.19	0.23	0.30
Green Bay, Wis.	0.37	0.41	0.47	0.21	0.24	0.30	0.14	0.17	0.23
Eau Claire, Wis.	0.37	0.41	0.47	0.20	0.24	0.30	0.13	0.16	0.22
La Crosse, Wis.	0.23	0.26	0.32	0.11	0.13	0.18	0.07	0.09	0.12
Mason City, Iowa	0.44	0.49	0.55	0.28	0.31	0.38	0.20	0.23	0.30
Minneapolis, Minn.	0.37	0.41	0.48	0.20	0.24	0.30	0.13	0.16	0.22
Moline, Ill.	0.37	0.41	0.47	0.20	0.24	0.30	0.14	0.16	0.22
Duluth, Minn.	0.38	0.42	0.50	0.20	0.24	0.31	0.13	0.16	0.22
Rochester, Minn.	0.55	0.59	0.66	0.36	0.40	0.48	0.26	0.31	0.38
Waterloo, Iowa	0.45	0.49	0.55	0.28	0.32	0.38	0.20	0.24	0.30
Rockford, Ill.	0.39	0.43	0.50	0.22	0.26	0.32	0.15	0.18	0.26

The specific energy output can easily be calculated by means of Eq. (5) and capacity factors in Table 5. Figure 12 shows the annual specific energy output E_s at 20 m height for the 12 stations and three wind machines as a function of the annual average wind speed. These data points are averaged over 6 yr: 1969-74. The relationship found between E_s and $\bar{v}$ is similar to the results of previous studies (Golding and Stodhart 1952; Tagg 1957; Justus et al. 1976).

SEASONAL AND DIURNAL VARIATION IN POWER OUTPUT

The seasonal variation in power output naturally follows the same pattern as the power in the wind, presented in Section 4. Appendix C

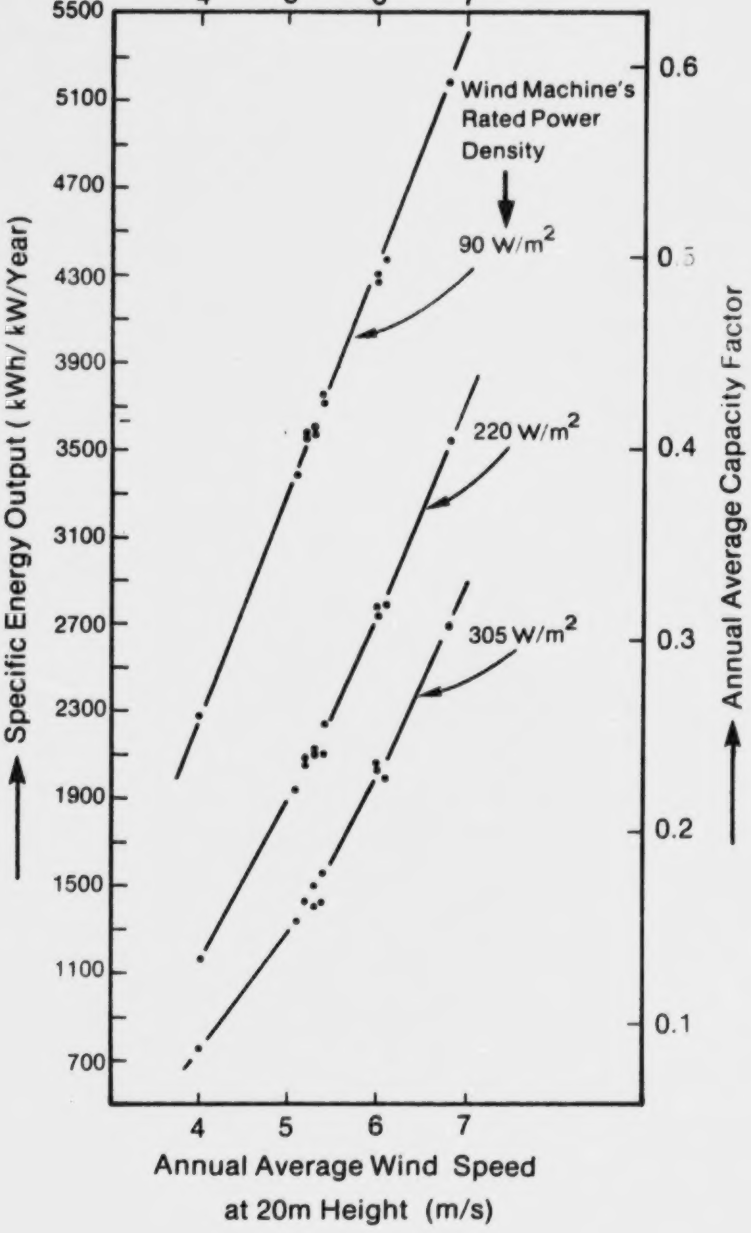

Figure 12. Specific energy output as a function of the annual average wind speed and rated power density of the wind machines. Calculated for the twelve airport sites (black dots). Data averaged over 6 yr.

contains the monthly average capacity factors for the three machines, three heights, and 12 locations. These graphs can be used to obtain an estimate of the monthly energy output of a machine chosen, at a given location and height. Note that the seasonal variation at a location with a high annual average wind speed such as Rochester is much larger than for La Crosse with a low annual average wind speed. In addition, this seasonal variation shows the same pattern as the heating degree days, which indicates that WECS could be used to (partially) meet a heating load. This aspect is further discussed in Section 7.

Figure 13 displays the diurnal average variation during four typical months for a wind machine with $P_{rd} = 90\ W/m^2$, averaged over 6 yr and three locations. The average over three locations simulates a WECS that consists of wind machines at different locations but interconnected by means of the electric grid. Such a system is commonly called an array of wind machines. The diurnal variation is small during the winter time and large during the summer months. Spring and fall show variations between these extremes. Note that the power output at higher elevations during nighttime in the summer months may be significantly underestimated due to the use of the 1/7-power law.

POWER DURATION CURVES FOR A SINGLE LOCATION AND FOR COMBINATIONS OF LOCATIONS

Figure 14 displays the power duration curves for two wind machines at 60 m height for both a single location and the same combination of locations as given in the previous paragraph. As can be seen, the percentage of time that a given output is equaled or exceeded is significantly larger for a wind machine with a lower rated power density. The curves for an array of wind machines indicate that the time a given power output is equaled or exceeded has increased for the lower and decreased for the higher power output levels. This phenomenon can be used when a more reliable system is desired.

Appendix D contains the power output duration curves for three wind machines, one height, and all 12 weather stations.

CONCLUDING REMARKS

The results and discussion of the analysis indicate the importance of a number of parameters in relation to the power and energy output of wind machines. For any application of a WECS, it is necessary to evaluate a variety of wind machines, tower heights, and locations in order to be able to choose a suitable system.

Wind power densities analyzed may vary with a factor of three, depending upon local terrain features. Wind power data presented here generally underestimate the true potential of the wind energy resource,

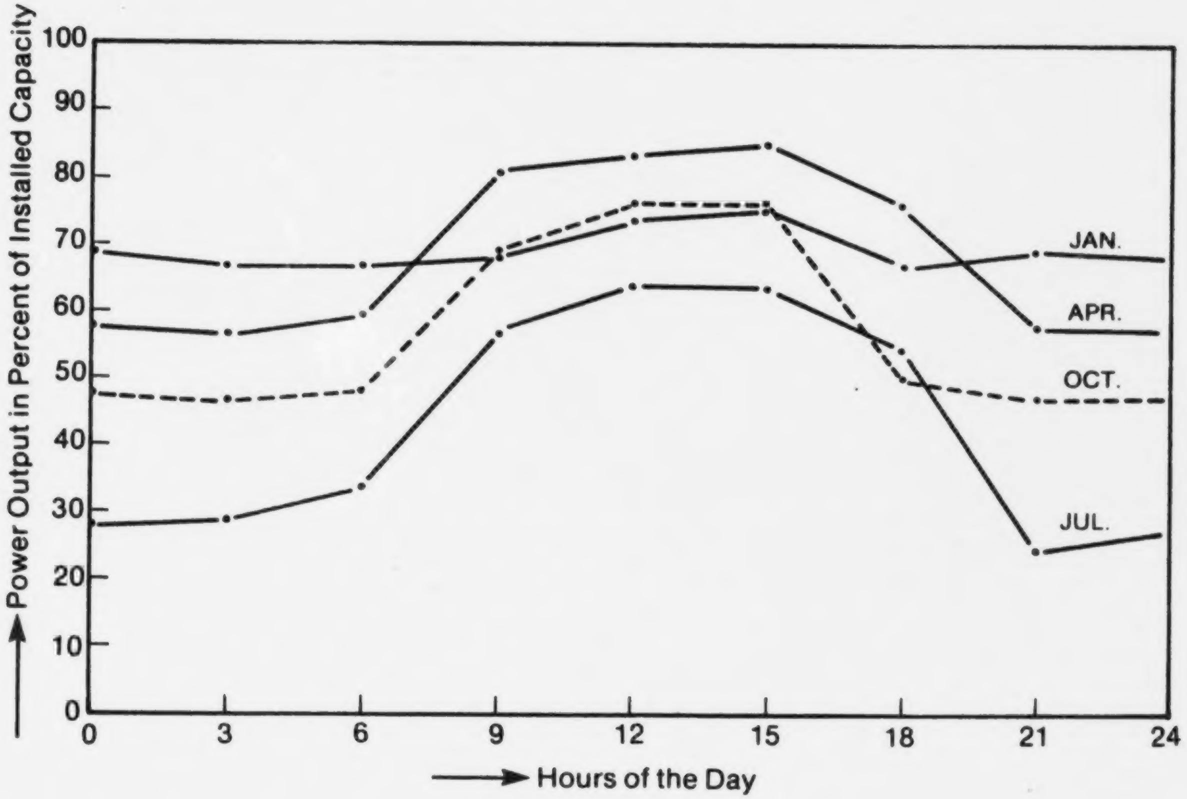

Figure 13. Diurnal variation in the power output of wind machines with a rated power density of 90 W/m^2, 1969-74.

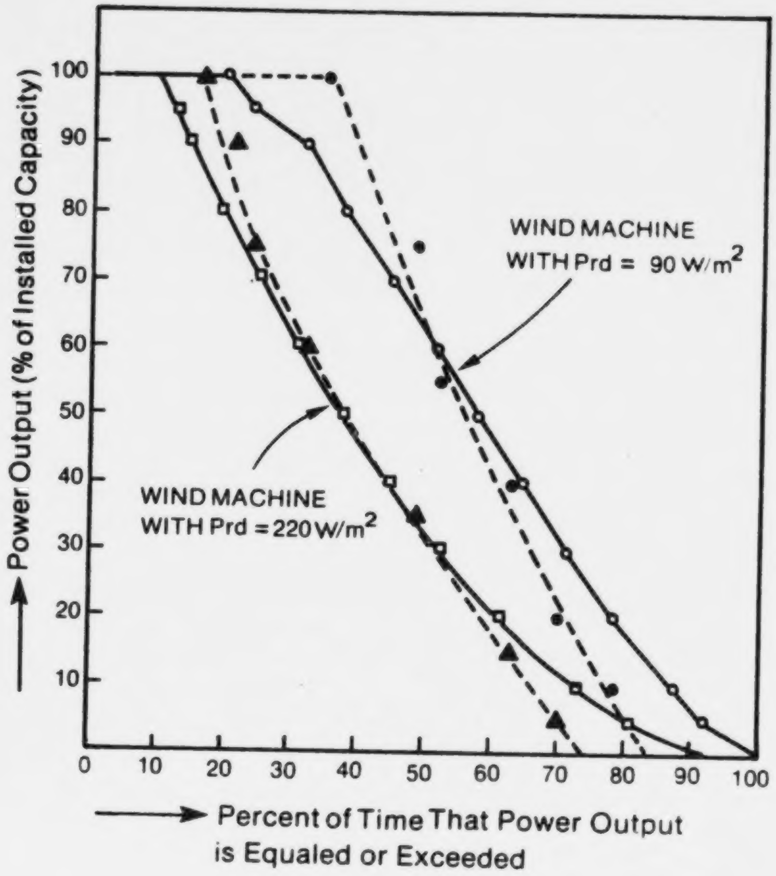

Figure 14. Power output duration curves for wind machines with rated power densities of 90 and 220 W/m^2, 1969-74.

since data from good windy locations are not available. Therefore, a wind energy survey is needed for an accurate assessment of WECS.

The intermittent nature of the wind and the wind speed variations over time require a detailed analysis of the WECS and utility load characteristics, if the WECS is connected to a utility grid. An array of wind machines spread out over a large geographical area may offer advantages as to the reliability of power output. These advantages have to be compared with the increased operating and maintenance costs of dispersed WECS, as well as the possible difference is cost of the electric transmission network.

SECTION 7

THE APPLICATION OF WIND ENERGY CONVERSION SYSTEMS TO AN ELECTRIC UTILITY: THE CASE OF THE DAIRYLAND POWER COOPERATIVE

REVIEW OF THE LITERATURE ON WECS--UTILITY APPLICATIONS

The Department of Energy's Wind Energy Program encompasses a variety of efforts to assess the potential of WECS. These research, development, and demonstration projects deal with economic, legal, technical, environmental, and social issues of large-scale (electric utilities, communities), as well as small- or intermediate-scale (homes, farms) applications of WECS (ERDA 1977).

A WECS integrated into an electric utility causes some special problems for utility systems management, since the WECS cannot be controlled as conventional generators. Utility operating managers decide daily on a dispatch scheme of conventional generators, which is a function of factors such as the expected daily load, relative cost of each unit, maintenance schedules, and energy purchasing or selling possibilities. However, wind availability is hard to predict on a daily basis. Consequently, a WECS cannot be counted on to meet a rising demand, to replace a unit that breaks down, or to meet part of the base load.

Some utility managers reject the integration of WECS into the utility until, as often argued, large-scale storage systems become available. Others are willing to consider WECS in addition to conventional generators needed for an expanding utility system.

In such a WECS utility system, a WECS will produce as much electricity as it can, since the fuel is free and operating and maintenance costs are not strongly dependent on operating time. Gross savings from the energy in the wind are primarily fuel savings, which explains the commonly used term "WECS as a fuel saver." Most studies up to now have assessed WECS in the "fuel saving" mode (JBF 1977a).

Recently, however, research has evaluated WECS as any other generator, employing the standard utility cost of production and reliability models. Johanson and Goldenblatt's study (1977) of the New England Gas and Electric Association (NEGEA) and Lindley and Melton's study of WECS in Hawaii (1977) indicate that a WECS added to a utility system will increase the reliability of the overall utility system. Consequently, some capacity credit should be given to the WECS.

This capacity credit may be obtained, for example, because new, capital-intensive, base-load capacity can be delayed or replaced by intermediate-load capacity. Thus, the conventional generating unit will change in a way that reflects reliability, cost of production, capital costs, and growth rate of the utility considered. Both studies indicate that the break-even cost of a WECS is significantly higher when fuel savings plus capacity credits are considered than when only fuel savings are considered. In other words, break-even costs of WECS that are calculated for WECS in the fuel-saver mode only represent the lower boundary and are therefore conservative.

Utilities evaluate alternative expansion plans for a given period in the future by a detailed economic analysis. The optimum system of generators meets the energy and reliability requirements with the lowest cost, in present value of annualized cost terms. A WECS utility evaluation contains the following steps, which may slighly vary (Johanson and Goldenblatt 1977; Melton 1977; Marsh 1978):

(1) Choice of wind machines and sites; estimate of desired total installed WECS capacity (often expressed as penetration level of WECS: ratio between WECS and conventional capacity.

(2) Calculation of the cost of production for various levels of WECS capacity. Predicted hour-by-hour wind power output data, based on historical wind speed observations, are subtracted from predicted hour-by-hour load levels that are based on historical load data and expected changes in future loads. These adjusted load levels for the period considered are used in the standard evaluation of electricity production costs with the given mix of conventional generators. These production costs without and with different penetration levels of WECS are used to estiamte gross savings (mainly fuel savings) over the total lifetime of the WECS. Given an estimate of lifetime operating and maintenance costs for the WECS, a break-even capital cost for the WECS can be calculated.

Both the fuel-saving mode and the more comprehensive analysis contain these first two steps. Note that up to now the conventional generating mix does not change when adding WECS capacity. Thus, fixed costs of the conventional system do not change when WECS capacity is added (provided that transmission and distribution changes are insignificant). Therefore, these costs cancel out and are not considered in a fuel-saving analysis.

(3) Adjustment of the conventional generating mix to find a new optimum for meeting the adjusted load. Both the fixed and variable costs are calculated with varying WECS penetration levels.

(4) The addition of WECS to a utility system results in a lower loss of load probability (LOLP)*. The effective capacity of the WECS is the amount of additional peak load that the system could meet or the conventional capacity that could be omitted to bring the LOLP back to its original level. This effective capacity determines the capacity credit.

(5) The final major task is the assessment of any potential increase in the operating reserve requirement due to unpredictability of the wind on a daily basis.

By comparing the fixed and variable costs for the conventional sources, capacity credits and operating reserve requirements for different penetration levels of WECS, savings and break-even costs can be calculated.

Some uncertainties in points 3 through 5 of this method still exist. For example, utility operators may often schedule generators as if WECS output equals zero, which may lead to high operating reserves. The Dairlyland Power Cooperative does not perform a separate reliability assessment of DPC's system, but instead relies on a power-poolwide reliability evaluation. Consequently, capacity credit evaluations are not included in this study. As previously stated, a fuel-saving analysis represents a conservative estimate of WEC's break-even cost.

A comparison of the results of other studies displays a variety of assumptions that have a significant influence on the conclusion whether a

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* LOLP = loss of load probability:

Historically, utility system planners measured generation system reliability with a percent reserves index. This planning design criterion simply measured the ratio of total installed generating capacity to the annual peak load demand. However, this approach proved to be a relatively insensitive indicator of system reliability, particularly when comparing alternative units whose size and forced outage rate vary.

Today, the accepted measure of generation system reliability is the "Loss of Load Probability" index (LOLP). The LOLP technique is a probabilistic measurement of the expected number of days per year on which the available capacity cannot meet the load demand. The LOLP index provides a consistent and sensitive measure of generation system reliability although the name, loss of load probability, is misleading in two respects. First, the index is not a probability, it is an expected value of the number of days per year of capacity deficiency. Second, it is not a loss of load, but rather a deficiency of installed available capacity. Despite the misnomers, the LOLP approach is a well accepted approach in the utility industry today (Garate 1977).

WECS may be economically attractive. The break-even cost of WECS strongly depends upon the mix of conventional generators of the utility considered. The regional studies for Hawaii (Lindley and Melton 1977) and the city of Hart (Asmussen et al. 1975, 1977), for example, pertain to utilities that are largely dependent upon oil. Break-even costs range from approximately $500 to $1,500 per installed kW capacity of WECS with various assumptions made. Estimated cost of wind machines, as given in Appendix E, fall within this range. Consequently, WECS appear to be a cost competitive alternative for these two particular utilities.

Other studies come to the opposite conclusion. The Honeywell study of the Minnesota Power and Light Company (MPL) (Malver 1976; Lindquist et al. 1977), for example, finds that WECS as fuel savers are too expensive. It should be noted, however, that MPL has a very high load factor due to an almost constant diurnal load. Consequently, this utility employs predominantly base-load generators burning cheap fuels. Another factor is the relatively poor choice of WECS sites with low average annual wind speeds.

Figure 15 displays a range of WECS break-even costs for the U.S. as reported in the General Electric Mission Analysis report (General Electric 1977; Garate 1977). A comparison of these break-even costs with the estimated WECS costs given in Appendix E indicates that WECS are not economically competitive under the assumptions made. Note, however, that no real fuel price increase has been included, which contradicts general expectations for future fuel prices.

Appendix E gives an overview of wind machine and site dependent costs for the studies summarized in the JBF report (1977a) on current costs estimates of large wind energy systems. Capital costs range from about $430 to $1,100 per installed kW capacity. It should be emphasized that there is uncertainty in the capital cost of the first production unit and in the learning curve to be applied to the following units. Appendix E also displays a method to calculate WECS energy costs and an overview of these energy costs of the studies considered. Energy costs vary between 24 and 62 mills/kWh, which is significantly higher than present coal and nuclear fuel costs and somewhat higher than present oil and gas costs.

This brief review of the literature on WECS utility applications reveals that an in-depth analysis of a WECS for a particular utility has to be made. Correlation of available wind and utility load characteristics, as well as expected fuel prices for the conventional generating mix are important factors that determine the economic viability of a WECS.

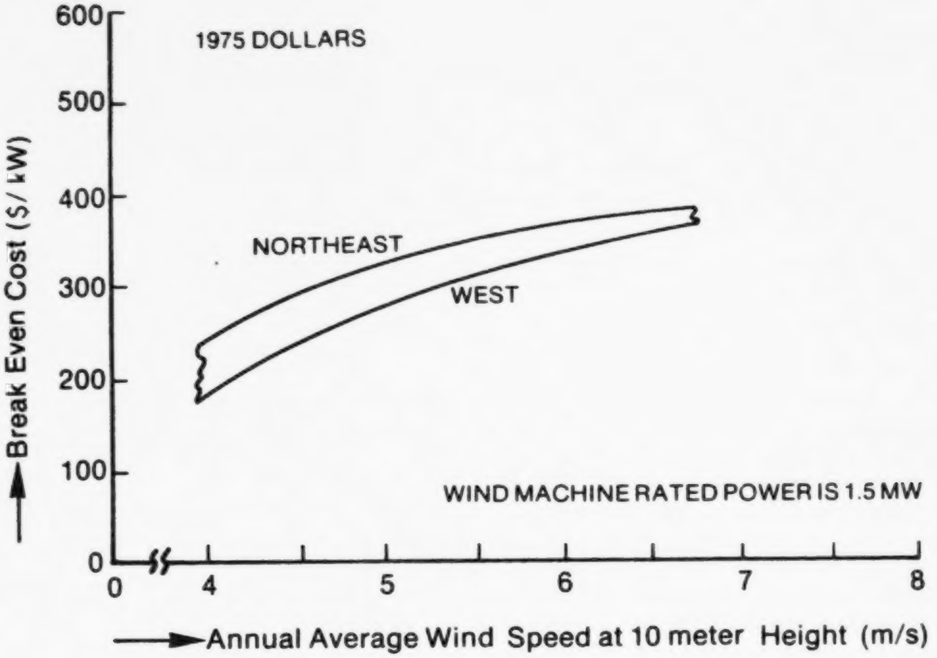

Figure 15. Maximum and minimum values of WECS break-even costs, assuming no real fuel price increase (Garate 1977).

WECS IN THE 'FUEL SAVING' MODE

The Dairyland Power Cooperative

A description of the characteristics of the DPC that are pertinent to this study is excerpted from the Revised 1976 Advance Plan of the Western Wisconsin Utilities (WWU 1978):

> Dairyland Power Cooperative (DPC) is a consumer owned non-profit generation and transmission cooperative headquartered in La Crosse, Wisconsin. It serves the energy supply needs of 29 member distribution cooperatives who in turn supply approximately 150,000 rural consumer-members. The member systems served includes 21 located in western Wisconsin, three located in southeastern Minnesota, four located in northeastern Iowa and one in northwestern Illinois.
>
> Dairyland Power Cooperative and the 29 member distribution cooperatives as Rural Electric Cooperatives finance all generation, transmission, and distribution facilities by means of federal loan funds administered by the Rural Electrification Administration. To obtain this financing each Rural Electric Cooperative must comply with all REA regulations which cover planning, load forecasting, engineering, construction, accounting, and service and reliability standards.
>
> Generation facilities operated by DPC are located at five generating stations with a total capacity of 695 MW, and consist of:

(a) Alma Generating Station

Unit 1	21 MW	Coal Fired Steam	(1947)
Unit 2	21 MW	Coal Fired Steam	(1949)
Unit 3	19 MW	Coal Fired Steam	(1951)
Unit 4	61 MW	Coal Fired Steam	(1957)
Unit 5	88 MW	Coal Fired Steam	(1960)

Total 210 MW

(b) Stoneman Generating Station

Unit 1	19 MW	Coal Fired Steam	(1951)
Unit 2	33 MW	Coal Fired Steam	(1954)

Total 52 MW

(c) Genoa Generating Station

Genoa #1	13 MW	Oil Fired Steam	( )
Genoa #2	48 MW	Nuclear Fired Steam	(1965)
Genoa #3	350 MW	Coal Fired Steam	(1969)

(d) Twin Lakes Generating Station

Units 1-4 9 MW Oil Diesel ( )

(e) Flambeau Generating Station

Units 1-3 16 MW Hydro (1951)

The 350 MW unit at Genoa is shared with Cooperative Power Association, a generation and transmission cooperative serving a number of distribution cooperatives in Minnesota. The sharing of this unit is a contractual commitment extending over the entire useful life of the plant. The commitment calls for CPA to be entitled to 50% of the capacity of the plant at all times.

In addition to the generation in service, Dairyland has a 350 MW coal-fired unit under construction at Alma, Wisconsin. This unit should be on line in 1979.

The average Dairyland member cooperative serves 5,000 members of which 45% are commercial farms, 50% are rural residential and 5% commercial and industrial. For this purpose, this average cooperative operates 1,400 miles of distribution line and has 25 full-time employees.

The DPC service area encompasses an agricultural region which produces dairy products, small grains, forage crops, livestock, and a variety of local specialty crops including cranberries, canning crops, poultry, and forest crops including Christmas trees, pulpwood, and sawlogs.

The typical agricultural enterprise is a full-time family farm with an average size of 81 ha (200 acres) which is highly mechanized and dependent to a great degree upon reliable electric service. Dairyland's membership also includes rural residential consumers located on the fringes of metropolitan areas and scattered throughout the rural region. Today's rural resident relies on electric service for light, heat, and power to operate water pumps, appliances, tools, furnace, and air-conditioning. In general, the rural residential consumer is more dependent on electric service than his urban counterpart. This is because most rural areas lack access to natural gas and to municipal water and sewer systems.

Approximately 76% of DPC's total energy requirements are for farm, rural residential, seasonal, and town residential consumers which make up 96% of the total consumers.

As a result of these member characteristics DPC's winter peaks are higher than summer peaks. Due to a substantial number of electrically heated homes and buildings, which roughly tripled during 1969-75, the DPC system is weather sensitive. The actual heating peak demand is estimated at about 11% of the total peak demand in 1975, with approximately 7% saturation based on the total membership of the DPC. Data obtained for 1976 show a continuation of this rapid growth rate. In addition, "Dairyland's annual peak occurs in the winter and always on days which are extreme from the standpoint of low temperature and high wind. Under these same conditions, electric space heating exhibits its highest demand for energy and loses most of its system diversity" (DPC 1975). Minnkota, another cooperative in the north-central region, has these same characteristics (Nelson 1976). The seasonal variation of DPC's load correlates with wind energy availability, which improves WECS cost competitive position. Dairyland's daily load curve during the winter shows a rapid rise in the load around 6:00 A.M., a moderate peak from 8:30 A.M. to 12:00 M, a slight reduction in load from 12:00 M to 4:00 P.M., and the daily peak between 6:00 P.M. and 8:00 P.M. The annual load factor for 1976 is 54%, which is relatively low in comparison with other utilities. Figure 16 displays DPC's annual load duration curve.

It is important to realize that a large part of the load of residential and dairy farm customers is for space heating and cooling, water heating, and milk cooling. These tasks require relatively low-quality energy sources, as clearly explained in a report by the American Physical Society (1975). Consequently, thermal storage systems may be employed to help meet these loads. Section 8 will cover these concepts in more detail.

In summary, the DPC load characteristics correlate to a higher degree with wind availability than for many other utilities. The weather-sensitive load during the winter months is expected to grow significantly in the near future for the DPC as well as other electric utilities in the north. Thus, winter peaking systems may become more common.

Dairyland Power Cooperative Proposed Expansion Plan, February 1978

Table 6 displays the historical and forecasted peak demand and energy requirements for the DPC for the period 1965-95 (Western Wisconsin Utilities 1978). These peak demands have been reduced from those given in 1976. The forecasts are made by evaluating the effects of, e.g., the substitution of electricity for alternate fuels for space heating, crop drying or irrigation, conservation efforts, load management, and rate restructuring. The annual peak is not the only demand figure dependent upon these factors.

For instance, an increase in electric crop drying will increase the monthly peak load in the fall, and electric heat load management will decrease monthly peaks in the winter months. Thus, monthly peak demands are monthly energy requirements are forecasted for the period considered, which in this case is 1978 to 95. Typical monthly peaks as a fraction of the annual peak are given in Table 7. (See Section III.A, pp. 1-265 through 1-332, of the Revised 1976 Advance Plan Supplement for a detailed discussion of the demand and energy projections.)

DPC expects only a slight improvement of the annual load factor for the period considered, which is displayed in Table 8 for a few selected years. Based on these load factors, no significant improvement of the annual load

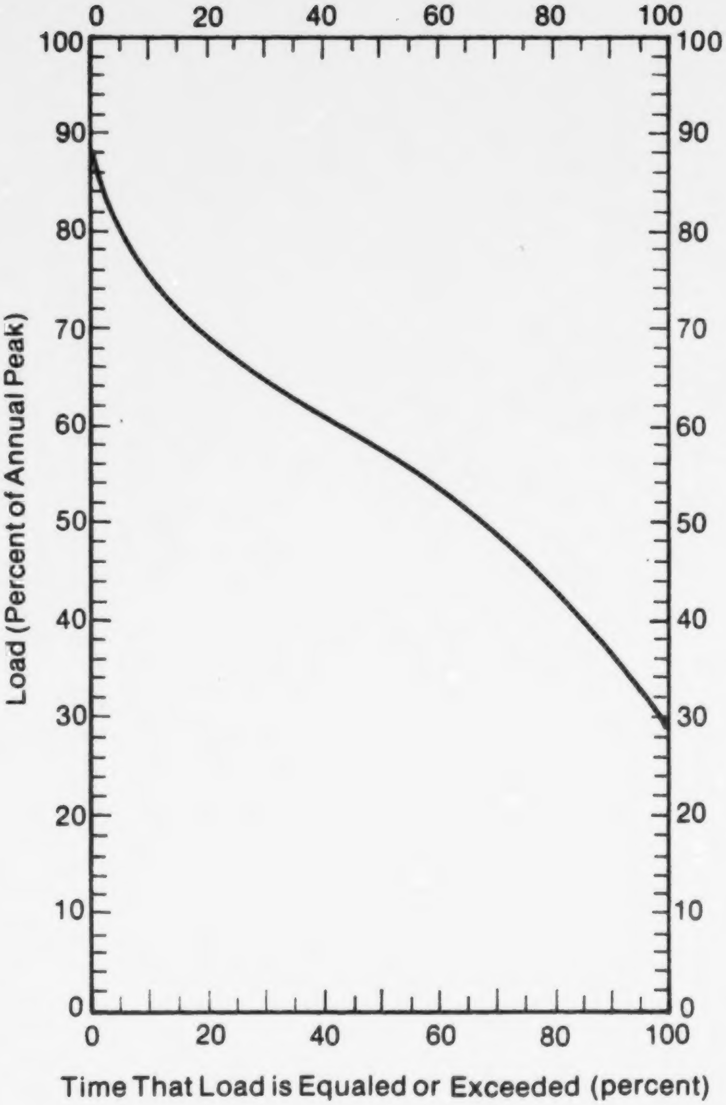

Figure 16. The Dairyland Power Cooperative annual load duration curve--1975 data.

TABLE 6. DAIRYLAND POWER COOPERATIVE PEAK DEMAND AND ENERGY REQUIREMENTS: HISTORICAL AND FORECAST

	Winter peak demand MW	Annual energy requirements GWh
	HISTORICAL	
1965	259	1215
1966	252	1297
1967	301	1371
1968	312	1463
1969	331	1620
1970	361	1793
1971	385	1851
1972	393	2047
1973	414	2076
1974	442	2200
1975	498	2410
1976	556	2626
	FORECAST	
1977	584	2860
1978	631	3075
1979	679	3314
1980	719	3546
1981	755	3798
1982	781	4065
1983	837	4349
1984	898	4651
1985	964	4978
1986	1035	5326
1987	1110	5698
1988	1190	6094
1989	1272	6516
1990	1360	6967
1991	1455	7447
1992	1555	7960
1993	1663	8502
1994	1773	9084
1995	1900	9705

TABLE 7. RELATIONSHIP OF MONTHLY PEAK LOADS TO THE ANNUAL PEAK LOAD, PROJECTED FOR 1988 FOR THE DAIRYLAND POWER COOPERATIVE

Month	Fraction of annual peak
January	1.0
February	0.96
March	0.90
April	0.83
May	0.72
June	0.81
July	0.81
August	0.81
September	0.76
October	0.84
November	0.95
December	1.0

TABLE 8. THE DAIRYLAND POWER COOPERATIVE PROJECTED ANNUAL LOAD FACTOR

Year	Annual load factor (%)
1976	53.9
1979	55.7
1984	59.1
1989	58.5
1994	58.5

duration curve is expected. The duration curve shown in Figure 16 approximates those for the total time period considered. Thus, the optimum mix of peak, intermediate, and base-load generation should approximately stay the same.

Given these forecasts of demand and energy requirements, several combinations of new generating units are evaluated. Cost characteristics of the generators considered can be found in Table 9. DPC has evaluated three alternative expansion plans for the period 1985 to 91:

Proposed plan	Alternative 1	Alternative 2
Tyrone 1, 1985	Alma 7, 1985	Alma 7, 1985
Southern Minn., 1987	Tyrone 1, 1987	Southern Minn., 1987
Nuclear, 1991	Nuclear, 1991	Nuclear, 1991

The proposed plan is the cost-effective alternative under the assumptions made.

The economic analysis examines fixed costs for the lifetime of the proposed plan and the production costs during the period 1985-91. Important parameters for the calculation of fixed costs are given in Tables 9, 10, 11, and 12. Note that the discount rate is equal to 9% (Table 12). The fixed charge rate (FCR) ranges between 10.8 and 11.6% and consists of:

Interest and depreciation: capital recovery factor, 9%, 35 yr = 0.09464

Decommissioning cost: sinking fund factor, 9%, 35 yr = 0.00464. Nuclear = 10% of investment = 0.10 x 0.00464 = 0.000464;
Coal = 1.5% of investment = 0.015 x 0.00464 = 0.000069

Property taxes (including exemption for environmental control facilities: nuclear = 4% of investment, coal = 25% of investment):

	Minnesota	Wisconsin
Nuclear	0.02112	0.01728
Coal	0.0165	0.0135

Fixed operating and maintenance costs and insurance are not included in the FCR given in Table 12, but can be separately found in Table 9.

The interest or discount rate is the single most important component of the FCR. Generation additions prior to Alma 6 and Tyrone were financed by standard REA loan funds with a 2% interest rate, which represented a most important incentive for centralized rural electrification (and virtually eliminated the use of small electric wind machines). The decommissioning costs of large radioactive nuclear facilties are unpredictable since nobody has yet had experience with these large facilities. Among the

TABLE 9. DAIRYLAND POWER COOPERATIVE GENERATION ALTERNATIVES: COST CHARACTERISTICS*

				Capital		Fixed O&M**	Insurance***	Variable O&M		Fuel	
										Consumed	Inventory
Unit	Fuel type	Size (MW)	Year to be completed	1-1-76 ($/kW)	Year Installed ($/kW)	1-1-76 ($/kW)	Year Installed ($/kW)	Year 1-1-76 ($/MWh)	Year Installed ($/MWh)	Year Installed ($/MBtu)	Installed ($/kW)
Alma #7	Coal	550	1985	482	749	3.41	0.59	1.20	2.21	2.27	3.79
Southern Minn.	Coal	800	1987	481	909	2.53	0.70	1.20	2.53	2.27	3.20
			1989	481	1041		0.90		2.89	2.52	6.26
Tyrone Energy Park #1	Nuclear	1100	1985	621	945	8.36	2.56	0.77	1.42	0.76	11.73
			1987	668	1109		2.75		1.62	0.86	13.36
	Nuclear	1100	1991	737	1500	8.36	3.16	0.77	2.12	1.11	14.49

* Generating units shared with other utilities.
** Annual escalation is 7%.
*** Annual escalation is 8%, except for Tyrone #1: 4%.

TABLE 10. DAIRYLAND POWER COOPERATIVE GENERATION ALTERNATIVES: OPERATING CHARACTERISTICS HEAT RATES*

Unit	Fuel type	No load (MBtu/hr)	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh	MW	Btu/kWh
Alma #7	Coal	943	138	8,700	220	9,000	480	10,700	550	11,500
Southern Minn	Coal	687	282	8,800	507	9,300	677	10,250	800	11,500
Tyrone Energy	Nuclear	919	281	9,000	500	9,500	842	10,300	1,100	10,950
Park #1	Nuclear	919	281	9,000	550	9,500	842	10,300	1,100	10,950

*Generating units shared with other utilities.

TABLE 11. DAIRYLAND POWER COOPERATIVE GENERATION ALTERNATIVES: OPERATING CHARACTERISTICS-OUTAGE RATES.*

				Forced outage rate			Unscheduled outage rate**		
Unit	Fuel type	Size (MW)	Planned outage (Wks/Yr)	Year 1 (%)	Year 2 (%)	Mature (%)	Year 1 (%)	Year 2 (%)	Mature (%)
Alma #7	Coal	550	4***	11.5	9.6	9.6	15.6	13.0	13.0
Southern Minn.	Coal	800	4***	16.8	14.0	14.0	20.4	17.0	17.0
Tyrone Energy Park #1	Nuclear	1100	6	18.1	14.9	10.7	23.8	19.6	14.0
Nuclear Minn. or Wis.	Nuclear	1100	6	18.1	14.9	10.7	23.8	19.6	14.0

* Generating units shared with other utilities.

** Percentage not including planned outages, but including forced outage rate.

*** 6 weeks/yr every fifth year for turbine overhaul.

decommissioning options under consideration are partially or totally demolishing the facility and sealing plus patrolling the entire site.

TABLE 12. ASSUMPTIONS MADE FOR THE FIXED COST ANALYSIS OF THE ALTERNATIVE EXPANSION PLANS OF THE DAIRYLAND POWER COOPERATIVE

Effective rate of return (discount rate)	= 9%	
Facility life	= 35 yr	
Property tax Wisconsin	= 1.8%	
Property tax Minnesota	= 2.2%	
Property tax exemption for environmental control facilities:		
Nuclear	= 4% of the investment	
Coal	= 25% of the investment	
Decommissioning cost:		
Nuclear	= 10% of the investment	
Coal	= 1.5% of the investment	
Fixed charge rate (FCR):		
	Minnesota	Wisconsin
Coal	11.12%	10.82%
Nuclear	11.62%	11.24%
Fixed O amd M and insurance	See Table 9.	

Table 13 displays the present worth (for the year 1985) of the fixed costs for the proposed plan's expansion. Since fixed costs of the conventional generators do not change when a WECS is added to the system, these costs are of less interest in the context of this study. More details can be found in the Revised 1976 Advance Plan (Western Wisconsin Utilities 1978).

A computer program--PROGEN--developed at Northern States Power Company, is employed to calculate production costs of the alternative expansion plans, to compare alternative methods of operation, to estimate fuel consumption, and to provide a loss of load probability analysis (Nordling 1973). The major inputs for this simulation model are:

(1) Monthly load duration curves for 1976. These curves and the monthly peak demands forecasted for future years are used to construct monthly load duration curves for the period 1985-91. In addition, these forecasts contain monthly energy requirements.

(2) Characteristics of each generating unit include capacity, fuel type, no-load energy use, incremental heat rate curve, planned outage, maintenance specifications, and fuel cost. Generating units are chosen according to increasing costs based on fuel, heat rate, and incremental operating and maintenance expense (Western Wisconsin Utilities 1978). When necessary, DPC purchases energy at generally average prices.

TABLE 13. THE PRESENT WORTH FOR THE YEAR 1985 OF THE FIXED COSTS FOR THE PROPOSED PLAN OF THE DAIRYLAND POWER COOPERATIVE (J.P. Leifer 1978; personal communication)

	$1,000
Revenue requirements on investment	472,100
Fixed O and M	92,000
Insurance	11,300
Fuel Inventory	4,800
TOTAL	580,200

Table 14 displays fuel prices in current dollars for the time period considered as assumed for the assessment of the alternatives. The irregular price of nuclear fuel during the initial years is caused by certain fuel replacement procedures for new nuclear power plants. As shown, coal prices are assumed to increase at a rate of 7% per yr, oil about 8%, and nuclear fuel 7 to 8%. The inflation rate beyond 1982 is assumed to be equal to 6%. Table 15 shows the total energy production costs for the proposed plan for the time period 1985 to 91. These costs are lower than those of the two alternatives, mainly because the proposed plan relies less on coal-fired units. As indicated in the table, fuel costs determine the total energy production costs to a large extent.

My discussion of Dairyland's proposed plan covers the major characteristics that are pertinent for an understanding of the analysis of WECS added to this proposed plan. An analysis of WECS as a fuel saver focuses on the differences in energy production costs. Thus, data displayed in Table 15 will be compared with those for the proposed plan + WECS.

The calculation of energy production costs is sensitive to assumptions of fuel price increases. The annual coal price increase employed (Table 14), e.g., is 1% higher than the estimated inflation rate, but the average cost of coal in the United States doubled between 1973 and 1975 in current dollars (Bupp and Derian 1978). This and other related issues are further discussed later in this chapter.

TABLE 14. FUEL PRICES IN THE EVALUATION OF ALTERNATIVE EXPANSION PLANS. CURRENT DOLLARS, RATE OF INCREASE INCLUDES INFLATION

	Nuclear		Western coal*		70/30 blend coal		Oil	
Year	$/MBTU	% increase	$/MBTU	% increase	$/MBTU	% increase	$/MBTU	% increase
1985	0.919		1.913		2.030		4.8	
1986	0.903	-1.8	2.046	7.0	2.172	7.0	5.18	7.9
1987	0.826	-8.5	2.190	7.0	2.324	7.0	5.60	8.1
1988	0.887	7.4	2.343	7.0	2.486	7.0	6.04	7.9
1989	0.975	9.9	2.507	7.0	2.660	7.0	6.53	8.1
1990	1.047	7.4	2.683	7.0	2.847	7.0	7.05	8.0
1991	1.128	7.7	2.870	7.0	3.046	7.0	7.61	7.9

* Prices for Alma 6; western coal for Alma 7, Southern Minnesota slightly more expensive.

TABLE 15. DAIRYLAND POWER COOPERATIVE: PROPOSED GENERATION EXPANSION PLAN, TOTAL ENERGY PRODUCTION COSTS IN CURRENT DOLLARS X 10^6

Year	Fuel costs	Variable O&M	Energy purchases	Total production
1985	98.5	8.2	3.1	109.8
1986	108.0	9.3	2.9	120.2
1987	122.9	11.7	2.5	137.1
1988	141.1	13.7	1.6	156.4
1989	161.5	15.7	2.6	179.8
1990	184.4	17.7	5.2	207.4
1991	184.9	19.6	3.8	208.3

Dairyland Power Cooperative Proposed Expansion Plan and WECS

This analysis of the application of a WECS to the DPC only encompasses the savings in energy production costs due to a WECS. No capacity credit considerations are included. Figure 17 contains a flow chart of the major components of my ivestigation and my procedures and assumptions are described as follows:

Table 1 showed the annual average wind speed for locations in and around Wisconsin. The cities of Rochester, Mason City, and Waterloo have relatively high annual average wind speeds between 7 and 8 m/sec at a height of 60 m (1/7-power law). These cities represent good locations for a large part of DPC's system and are therefore chosen for this study. It is assumed that the WECS consists of wind machines equally spread over these three locations. The power output of this array of wind machines enters the calculation procedure.

Table 4 displayed characteristics of three wind machines, of which the two with a rated power density of 90 and 220 W/m^2 were chosen for this study. Annual average capacity factors of these two machines at 60 m for the three locations chosen range from 0.38 to 0.66 (Table 5). In addition, the diurnal variation of power output and the annual power output duration curves for an array of wind machines at the three locations were shown in Figures 13 and 14. The annual average capacity factor for the array is 0.58 for the 90 W/m^2 wind machine and 0.41 for the 220 W/m^2 wind machine.

Three levels of installed WECS capacity were chosen: 100, 200, and 400 MW. These capacities were assumed to be in place at the beginning of 1985 and kept constant throughout the period of analysis. WECS penetration levels vary between 10 and 40% for the year 1985 and decrease thereafter. Table 16 indicates monthly and annual energy output for the two types of wind machines for arrays with installed capacity of 100 MW. These energy figures represent about 7 and 10% of the DPC 1985 forecasted energy requirements (Table 6),if 100 MW of 200 and 90 W/m^2, respectively, wind machines are installed. Data given in Table 16 served as an input in the production cost calculation.

A computer model was employed to construct new monthly load duration curves. WEC's array power output, based on 1969 to 73 wind speed observations, is subtracted from predicted load levels on an hour-by-hour basis for all years of the analysis: 1985-91. Figures 18a and 18b displays the change in the DPC 1985 annual load duration curves due to the addition of WECS with installed capacities of 100, 200, and 400 MW. Note that these curves are significantly steeper than the DPC curve without WECS, which means that the mix conventional generators may contain less base-load and more intermediate-load generators. As previously noted, however, this analysis does not include considerations of capacity credits.

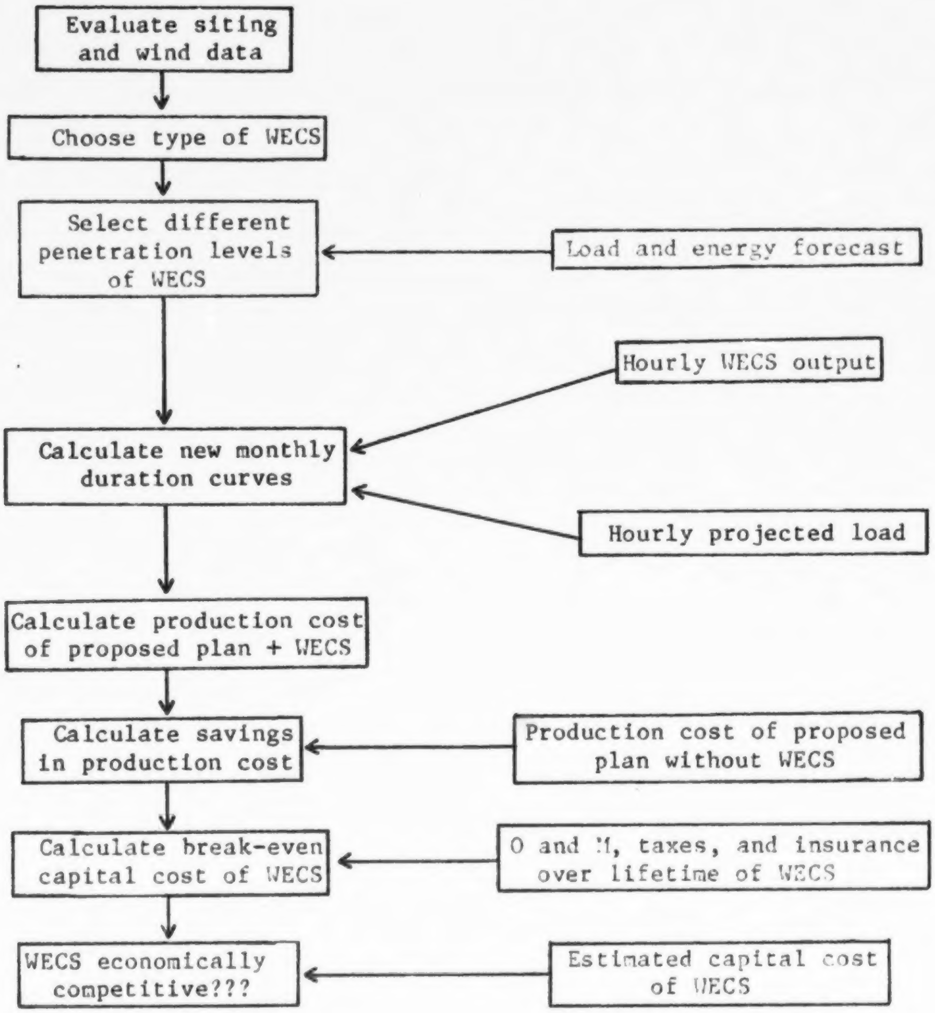
Evaluate siting and wind data
Choose type of WECS
Select different penetration levels of WECS
Load and energy forecast
Hourly WECS output
Calculate new monthly duration curves
Hourly projected load
Calculate production cost of proposed plan + WECS
Calculate savings in production cost
Production cost of proposed plan without WECS
Calculate break-even capital cost of WECS
O and M, taxes, and insurance over lifetime of WECS
WECS economically competitive???
Estimated capital cost of WECS

Figure 17. Flow chart of major components of the analysis.

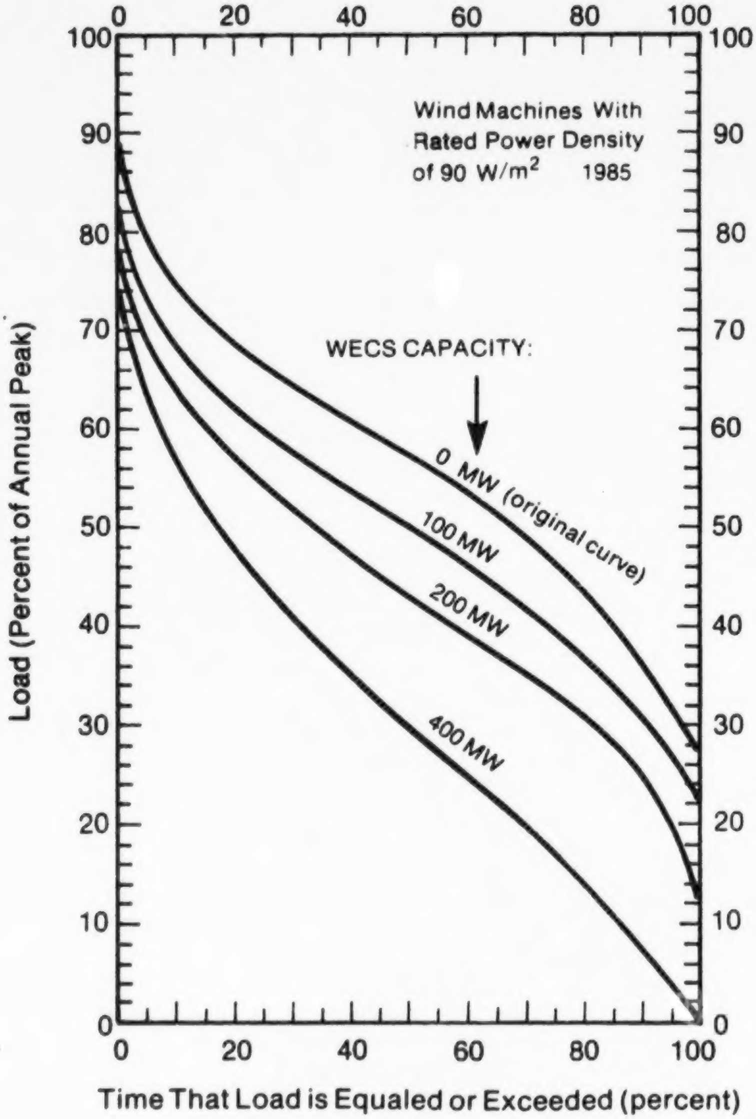

Figure 18a. Change in the Dairyland Power Cooperative 1985 annual load duration curve by WECS of 100, 200, and 400 MW capacity.

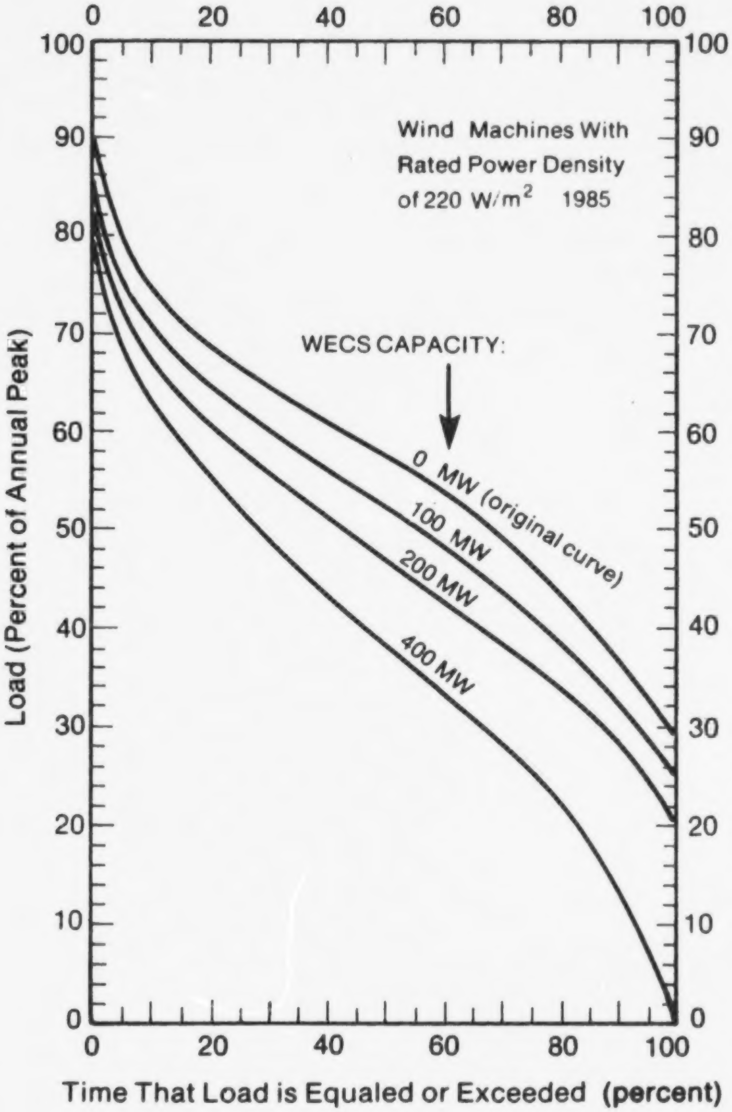

Figure 18b. Change in the Dairyland Power Cooperative 1985 annual load duration curve by WECS of 100, 200, and 400 MW capacity.

TABLE 16. MONTHLY AND ANNUAL ENERGY OUTPUT OF WIND MACHINES WITH RATED POWER DENSITY OF 90 AND 220 W/M^2. HUBHEIGHT = 60 M. ARRAY: ROCHESTER, MASON CITY, WATERLOO. AVERAGED OVER 5 YR. 1969 TO 1973. INSTALLED CAPACITIES OF 200 AND 400 MW INCREASE OUTPUT ACCORDINGLY

	Rated capacity of wind machine	
	90 W/m^2	220 W/m^2
	Monthly and annual energy (GWh) with installed capacity of 100 MW	Monthly and annual energy (GWh) with installed capacity of 100 MW
January	51.9	39.1
February	44.9	33.6
March	46.2	33.4
April	50.3	38.8
May	44.5	31.8
June	39.5	26.5
July	33.1	20.5
August	31.6	18.5
September	33.7	21.2
October	43.0	29.1
November	44.1	31.3
December	47.3	34.0
ANNUAL	510	358

The standard computer program PROGEN calculated the production costs for the proposed plan plus WECS for the period 1985-91 in the same manner as is usually done for conventional alternative plans. Relevant input data, the monthly load duration curves, and the monthly energy requirements, have been changed as a function of the type of wind machine and the installed capacity of the array. All other assumptions remain the same.

Savings consist of the difference between the total energy production costs for the proposed plan plus WECS and the proposed plan only. The detailed hour-by-hour analysis results in an estimate of annual savings during the years 1985-91. However, since wind machines have an expected lifetime of about 35 yr when well-maintained, savings during the period 1992 to 2019 should be included, too. Therefore it was assumed:

(a) Constant annual fuel savings throughout the period 1991 to 2019 and escalating annual costs of fuels, variable operating and maintenance and purchased energy.

(b) All fuels, variable operating and maintenance costs, and purchased energy costs increasing at the same rate. (Since fuel savings represent more than 80% of the savings, this assumption does not introduce large inaccuracies.) Nuclear fuel and coal are the major components of fuel savings. It was assumed that the price of these fuels increases at the same rate of 6, 7, 8, 10, or 12%/yr, including inflation, for the period 1992 to 2019.

The cumulative savings in January 1985 dollars can be calculated by employing the following formulas:

The uniform present worth equation to be used for the period 1992 to 2019:

$$P_{92} = A \times \frac{1+e}{1-e} \left[1 - \frac{1+e}{1-i}^{n}\right] \qquad (7)$$

and the single present worth equation to calculate savings in January 1985 dollars:

$$P_{85} = F \times \frac{1}{(1+i)^{n}} \qquad (8)$$

where:

P_{92} = cumulative savings over 1992 to 2019 in January 1992 dollars (present value)

A = initial 1991 savings

e = fuel price increase, including inflation

i = discount rate = 9%, including inflation

n = number of years in time period considered

F = future savings for a given year. Note that P_{92} in formula 7 becomes F in formula 8

P = present sum of money, January of year indicated.

Equation (8) can also be employed to transfer January 1985 dollars into January 1979 dollars by setting i equal to the general expected inflation rate during 1979-85. DPC estimates the annual construction inflation rate to be 7%, which wil also be used for WECS. By dividing the total savings by the total WECS capacity, savings per kW of WECS in January 1979 or 1985 dollars can be obtained.

The next major component of the analysis is the calculation of the present worth of WECS's operating and maintenance costs, taxes, and insurance in order to obtain the break-even capital cost:

$$\text{PV (savings)} = I_{BE} + \text{PV (O\&M, taxes, insurance of WECS)} \tag{9}$$

where:

PV = present value

I_{BE} = break-even capital cost of WECS.

By expressing the present value of O and M, taxes, and insurance as a fraction F of the capital cost I_{BE}, Eq. (9) becomes:

$$I_{BE} = \frac{\text{PV (savings)}}{1 + F} \tag{9}$$

Values assumed in percentage of the capital cost are:

Wisconsin tax = 1.8%
Insurance = 0.1% (> DPC's assumption for coal, < for nuclear)
O and M = range of values: 1, 2, 3, and 4%
e* = annual increase in above: 6 or 7%.

The fraction F is calculated for a range of values by the ue of Eq. (7), substituting e* for e and N=35 yr.

Assumptions as to O and M dominate the value of F. Table 17 presents values of F for the range of assumptions made.

TABLE 17. PRESENT VALUE OF WECS O AND M, TAXES, AND INSURANCE OVER 35 YR LIFESPAN, AS A FRACTION F OF CAPITAL COSTS OF WECS. (EQ. 10)

	O and M (%)			
	1 Total	2 O and M	3 Taxes	4 Insurance (%)
1985-2019: Annual increase in O&M, taxes, insurance, %	2.9	3.9	4.9	5.9
6	0.64	0.86	1.08	1.30
7	0.74	1.00	1.25	1.51

Note: Values of F refer to January 1985.

Finally, a comparison is made between the calculated break-even capital costs of the WECS and the estimated costs of such a WECS, as given in Appendix E, to determine whether a WECS is economically attractive. As previously stated, these analyses are sensitive to the assumptions made, particularly as to fuel price increases and WECS O and M costs.

REDUCTION IN FUEL CONSUMPTION

Figure 19 displays the reduction in consumption of three types of fuels and a function of WECS capacity for the period 1985-91. Note that oil is measured in a unit that is a factor 10 smaller than for coal and nuclear fuel. The relative change in fuel consumption is the largest for oil and smallest for nuclear fuel, which reflects the difference in fuel prices. Coal consumption increases steadily until 1991, when a nuclear generating unit is installed. This additional nuclear plant reduces fuel costs for 1991 in comparison to 1990, with the assumptions made as to fuel costs.

Figure 20 shows 1985 capacity factors for the major DPC power plants as a function of the installed WECS capacity. The capacity factors for the proposed plan without WECS indicate that Alma 6 is the only major intermediate-load generator. The southern Minnesota coal plant (not shown in Figure 20) to be on-line in 1987 will also be a base-load generator. The Tyrone 1 capacity factor is expected to be 0.75, which appears to be high considering the average performance of new large nuclear generators (Council on Economic Priorities 1976). When WECS capacity is added, the Alma 6 capacity factor decreases in a straight line. The other coal-fired generator capacity factors hardly decrease with WECS capacity more than 100 MW, while Tyrone is not influenced at all. It is important to note that the capacity factors of Genoa 3 and Alma 6 decrease almost linearly when the WECS capacity is increased from 100 to 400 MW. Consequently, savings per kW of WECS do not significantly decrease when WECS capacity increases to 400 MW. This is a result of the specific operating characteristics of the DPC generators.

Figure 21 indicates cumulative coal consumption (Western + 70/30 blend coal) as a function of the WECS capacity.

Figures 19, 20, and 21 represent results of the simulations with wind machines that have a rated power density of 220 $/m^2$. Since wind machines with a lower rated power density have a higher capacity factor, energy savings are higher for the 90 W/m^2 wind machine. Table 18 gives an overview of total fuel savings over the 35 yr lifespan of the WECS.

The decrease in oil consumption is based upon the assumptions used in the production cost computer model of the DPC. However, in actual practice on the DPC system, oil savings due to the operation of WECS will probably not be shown in Table 18. Currently, greatest use of oil by DPC is for flame stabilization and start-up of coal-fired units. The use of WECS may require coal-fired units to cycle, resulting in higher use of oil.

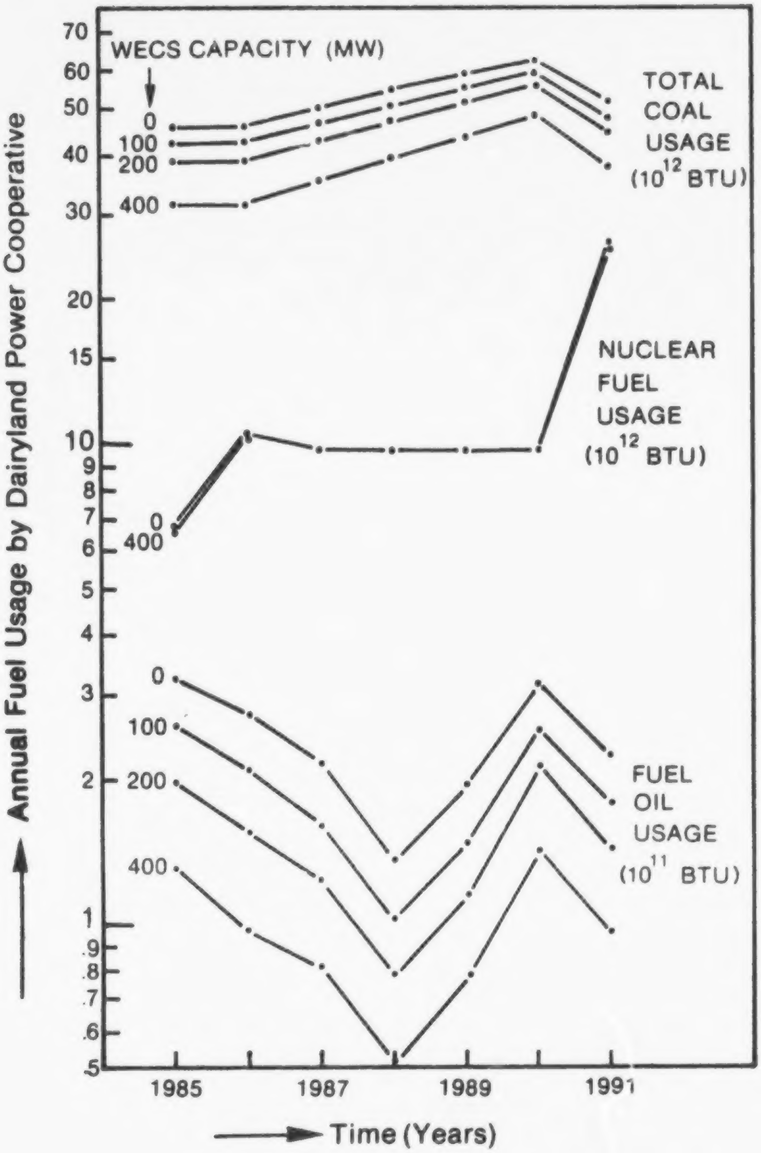

Figure 19. The Dairyland Power Cooperative annual coal, nuclear fuel, and oil usage as a function of WECS capacity for 1985-91.

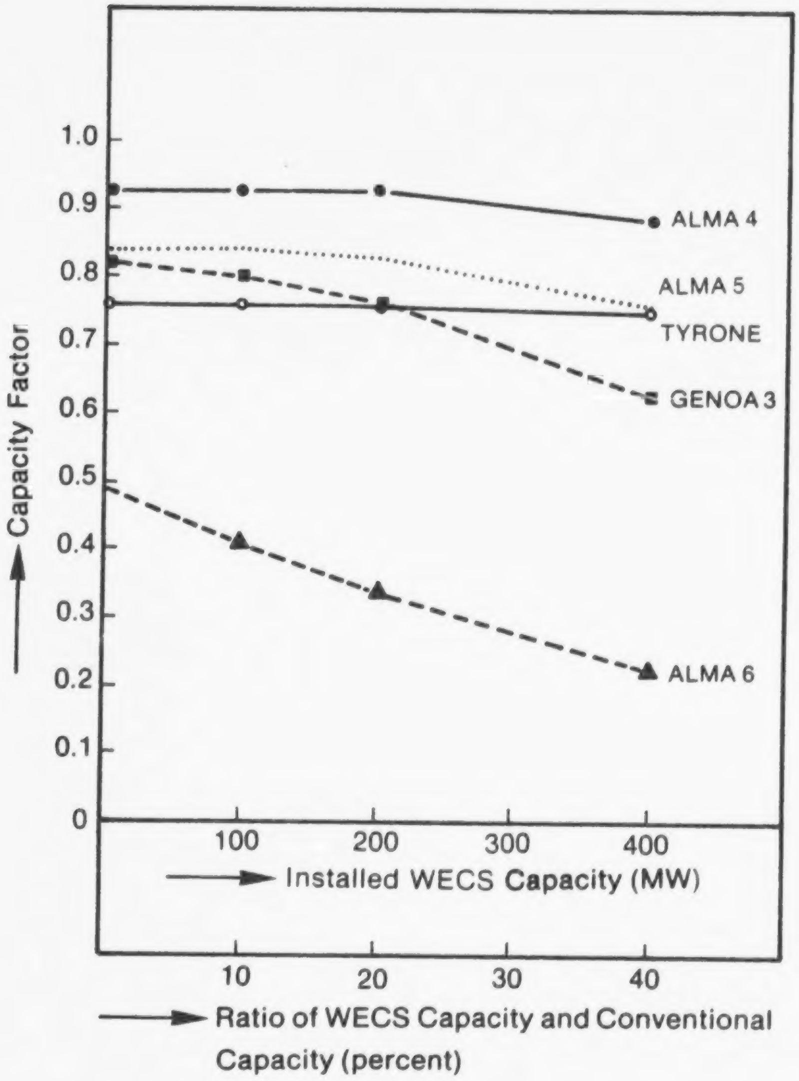

Figure 20. Capacity factors of the Dairyland Power Cooperatives major generating units in 1985 as a function of the WECS capacity installed. Wind machine rated power density is 220 W/m^2.

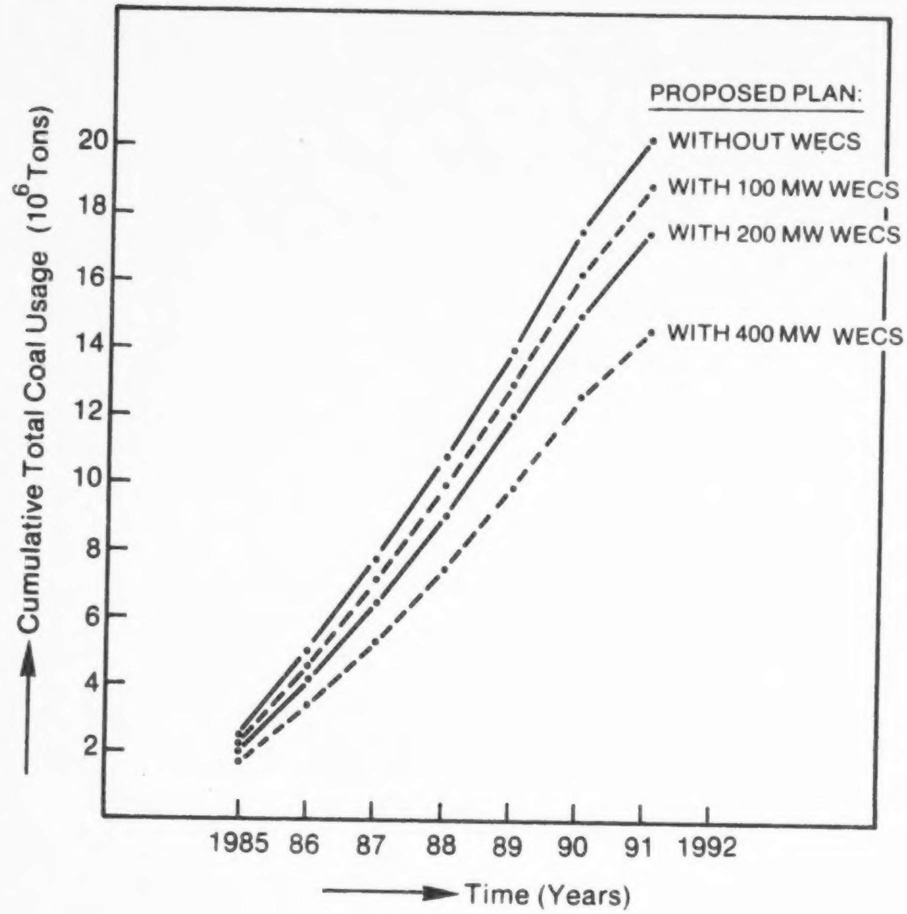

Figure 21. Cumulative total coal usage by the Dairyland Power Cooperative, 1985-91. Proposed plan without and with WECS. Wind machines with rated power density of 200 W/m^2.

TABLE 18. CUMULATIVE FUEL SAVINGS WITH A WECS OF 100 MW. WIND MACHINE RATED POWER DENSITY OF 90 AND 220 W/M^2. ANNUAL FUEL SAVINGS DURING 1992 TO 2019 ASSUMED TO BE EQUAL TO THOSE OF THE YEAR 1991

	220 W/m^2			90 W/m^2		
	Western coal (10^6 tons)	70/30 coal blend (10^6 tons)	Oil* (10^6 Gal)	Western coal (10^6 tons)	70/30 coal blend (10^6 tons)	Oil* (10^6 Gal)
1985-91 savings	0.96	0.45	2.7	1.37	0.64	3.7
(in %)	(8.1)	(5.3)	(22.3)	(11.4)	(7.6)	(31.0)
1992-2019 savings	3.70	1.68	8.96	5.26	2.46	12.0
(in %)	(7.1)	(6.0)	(20.0)	(10.1)	(8.8)	(26.6)
Total Savings	4.7	2.1	11.7	6.6	3.1	15.7

* See text about uncertainties in the reduction of oil consumption.

AN ECONOMIC ANALYSIS

Production Costs Savings

Savings due to the WECS equal the difference between the production costs of the proposed plan (Table 15) and of the proposed plan plus WECS. Table 19 gives and overview of annual savings during the period 1985-91 for 100 MW of wind machines with a rated power density of 220 W/m^2. Generally, more than 80% of these savings consist of a reduction in fuel costs. The annual savings for 1991 show a decrease in comparison to previous years (1985 dollars), which is primarily caused by the new nuclear generating unit. In addition, Table 20 displays the cumulative savings during 1992 to 2019, employing Eqs. 7 and 8 and the assumptions already outlined. Adding the savings during these two periods together results in total savings and savings per kW of installed WECS capacity.

Figure 22 shows a graphical representation of production costs savings per kW of WECS as a function of the annual fuel price increase during 1992-2019, the type of wind machine, and the total installed WECS capacity. Obviously, fuel price increases have a significant influence on these savings. The difference in savings between the 90 and 220 W/m^2 wind machines is to be expected, but should be compared with differences in capital cost of these wind machines. Savings per kW of WECS do not

TABLE 19. ANNUAL SAVINGS IN ENERGY PRODUCTION COST. WIND MACHINE RATED POWER DENSITY OF 220 W/M^2. WECS CAPACITY IS EQUAL TO 100 MW. DATA IN CURRENT MILLION DOLLARS

Year	Fuel Savings	Variable O and M	Energy purchases	Total Saving
1985	7.2	0.6	0.7	8.5
1986	7.5	0.6	0.9	9.0
1987	8.6	0.7	0.7	10.0
1988	9.2	0.7	0.4	10.3
1989	9.5	0.8	0.7	11.0
1990	9.8	0.8	1.2	11.9
1991	10.5	0.8	1.0	12.2

TABLE 20. TOTAL SAVINGS OVER 35 YR LIFETIME OF THE 220 W/M^2 WIND MACHINE AND WECS CAPACITY OF 100 MW

	Annual increase in fuels, O and M, energy purchases (%)					
	5	6	7	8	10	12
1992-2019 savings (January 1985 Million $)	114	129	145	165	215	285
1985-2019 savings (January 1985 Million $)	166	180	197	216	266	337
Savings per KW of WECS (January 1985 $)	1,660	1,800	1,970	2,160	2,660	3,370
Savings per KW of WECS (January 1979 $)*	1,110	1,200	1,310	1,440	1,770	2,250

*Deflated from 1985 to 1979 with 7% annual, which is the Western Wisconsin Utilities (1978) estimated construction inflation rate. It is assumed that the constructin cost of wind machines will increase at this rate during this period.

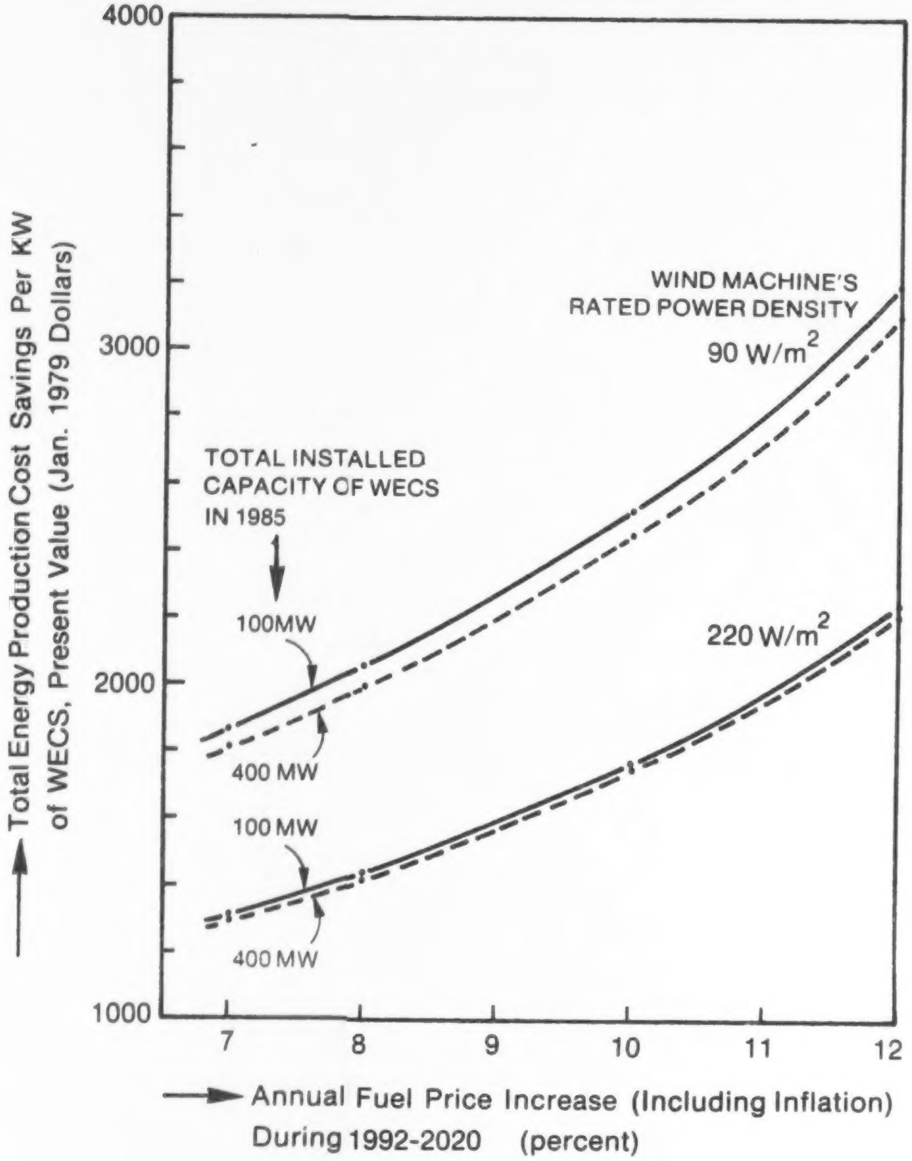

Figure 22. Total energy production cost savings per kW of WECS as a function of annual fuel price increase. (Rated power density of 90 and 220 W/m^2. Total installed WECS capacity of 100 and 400 MW in 1985.)

dramatically change when the total installed WECS capacity increases from 100 to 400 MW (penetration levels of 10 and 42%, respectively, in 1985). As shown in Figure 20, this small change in savings per kW of WECS is due to the characteristics of the DPC generating units.

Johanson and Goldenblatt (1977), Lindley and Melton (1977), and Marsh (1978) have found a significant decrease in savings per kW of WECS when the penetration level increases.

Break-Even Capital Cost of WECS

The break-even capital cost of WECS is obtained by subtracting the present value of O and M costs, taxes and insurance for the WECS over a 35-yr time period from the savings reported in the previous paragraph. Equation (10) and data displayed in Table 17 are used to calculate the break-even cost of the WECS.

Figures 23 and 24 give a graphical representation of the break-even capital cost of the 220 and 90 W/m^2 wind machines, as a function of annual fuel price increase, WEC's O and M costs in percentage of capital cost, and the annual increase in O and M, taxes, and insurance for a WECS. The break-even cost varies significantly depending upon the assumptions made. Fuel price increases and O and M costs of WECS are important parameters. JBF Scientific Corporation (1977a) estimates annual O and M costs at 3% for megawatt scale WECS. But a lower cost of about 1% may be possible for mature WECS design (Meyer 1978), which will significantly increase the break-even cost. With an annual fuel price increase equal to or exceeding 7% during 1992 to 2020, the minimum break-even cost for the 220 W/m^2 machines is about \$600/kW and for the large 90 W/m^2 machines about \$850/kW. Break-even cost for smaller machines may be lower, if O and M costs are higher.

Comparison of Estimated Cost of WECS and the Break-Even Costs

Although wind energy technology has been used for many centuries, WECS on a megawatt scale are in some aspects a relatively new technology in an early stage of development. Consequently, uncertainty exists in both the cost of the first production unit and the reduction in costs due to increased production quantities. Federal incentives assist in the development and commercialization of many types of energy technologies, although one may judge the success and desirability of this type of federal programs differently (Cone et al. 1978). It is generally assumed that R and D and large production quantities will bring the cost of WECS down to a level where these WECS become economically attractive.

Another aspect in the uncertainty of costs is the question whether large megawatt wind machines will be cheaper per kW installed than wind

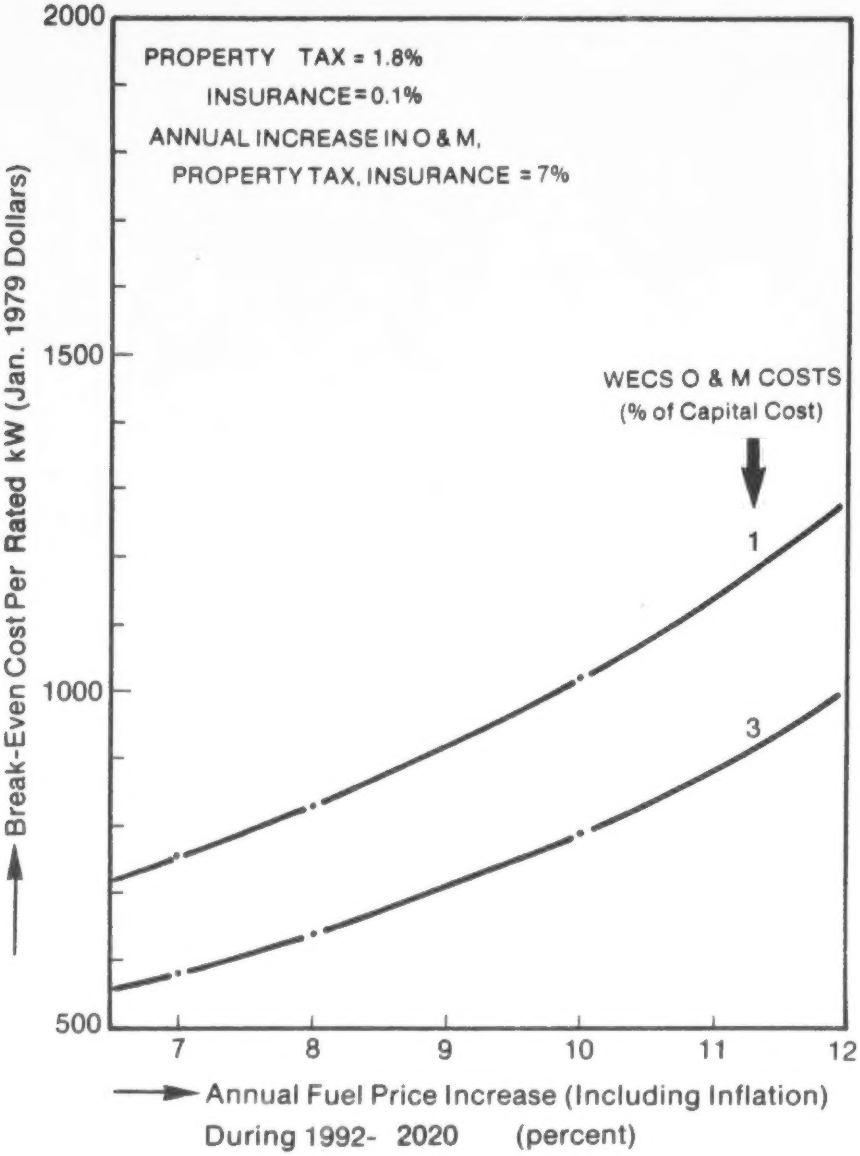

Figure 23. Break-even capital cost of wind machine with rated power density of 220 W/m^2. (Break-even capital cost per kW of WECS as a function of annual fuel price increase and annual WECS O and M cost. WECS capacity installed is 100 MW in 1985. Break-even cost slightly lower for WECS capacity of 200 and 400 MW.)

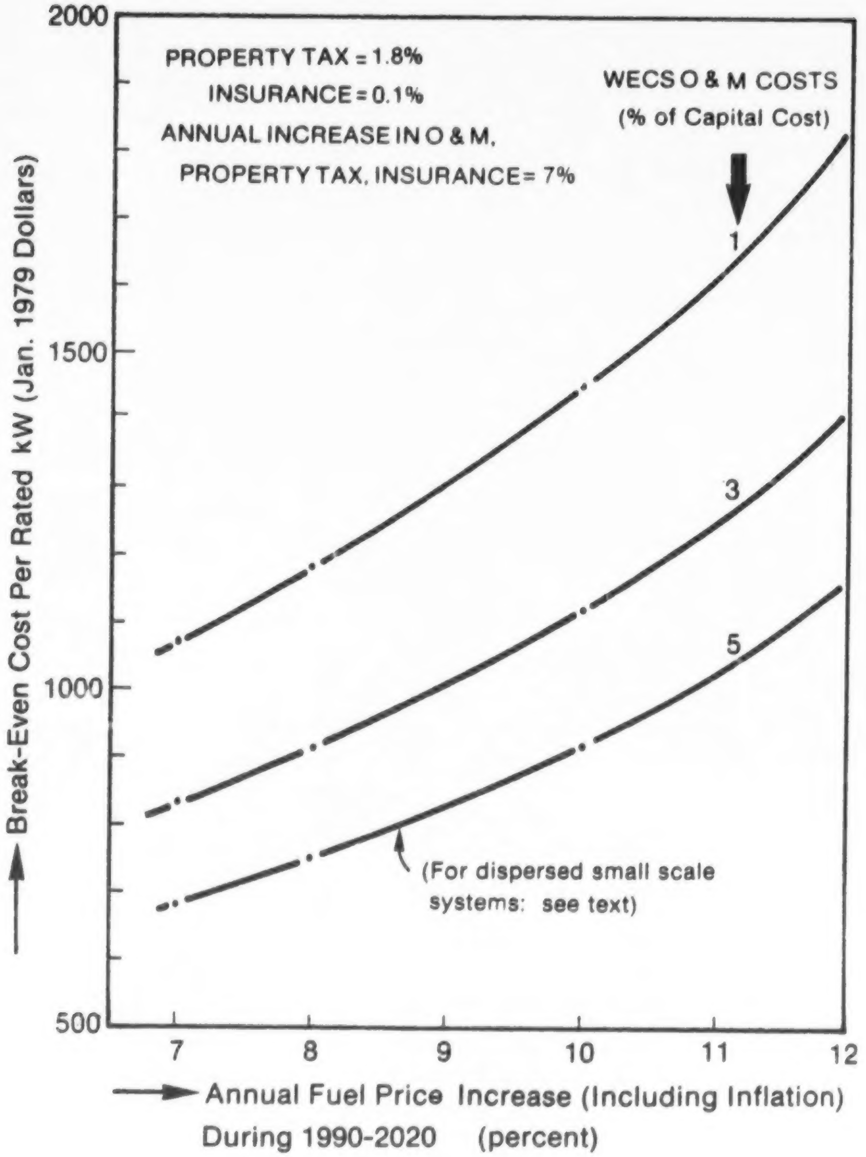

Figure 24. Break-even capital cost of wind machine with rated power density of 90 W/m^2. (Break-even capital cost per kW of WECS as a function of annual fuel price increase and annual WECS O and M cost. WECS capacity installed is 100 MW in 1985. Break-even cost slightly lower for WECS capacity of 200 and 400 MW.)

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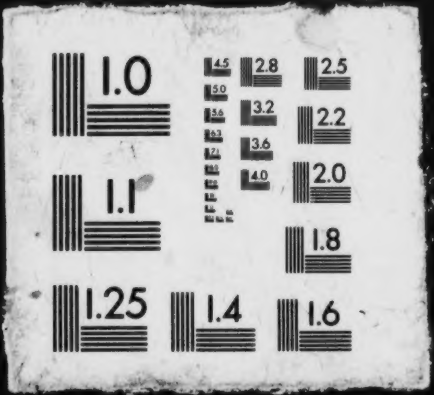
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machines in the range of 10 to 100 kW. While megawatt-sized wind machines benefit from scale, small wind machines may make better use of the economies of the assembly line. At present, wind machines of the 10 kW size generally cost about $1,000/kW, which will decrease at higher production levels. A WECS utility interface will add about $150/kW to this price (Windworks 1978). Latest cost figures are as low as $250/kW for wind machines of about 25 kW (International Project for Soft Energy Paths 1978).

Appendix F gives an overview of available cost estimates (in 1975 dollars) for wind machines of megawatt size (JBF Scientific Corporation 1977a). The capital costs consist of machine- and site-dependent costs. Wind machine costs vary from $400 to $900/kW, when normalized at a 100-unit production level with a learning curve* of about 95%. Site-dependent costs range from $27 to $160/kW for the megawatt scale machines, which are spaced roughly 10 to 15 diameters apart. Lower cost may be possible, as indicated by a large new WECS bought by Southern California Edison for $356/kW from Wind Power Products, Seattle, Washington. Subsequent units are estimated at costs below $250/kW in 1978 dollars for a turnkey installation (International Project for Soft Energy Paths 1978).

General Electric is building two wind machines as part of the Federal Wind Energy Program. The contract cost of installing the second 1.5 MW windpower system, including a 10% factor for transmission lines, is $1,586/kW (1975 dollars). With a hundred units production level, this contract cost amounts to $680/kW for a LC = 90% and $1,100/kW for a LC = 95%. These costs are close to the estimates given in Appendix E, but much higher than those quoted for Southern California Edison.

The rated power density of a wind machine is an important characteristic reflected in the significant difference between the break-even cost for the 220 and 90 W/m^2 wind machines used in this study. Since the cost of the wind machines also depends upon the rated power density, care should be taken in comparing break-even costs and estimated cost of a

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* Learning Curve (LC):
It is generally true, up to some maximum production number, that the greater the number of units produced, the lower the unit cost of production. This effect is called the learning curve, which establishes the fractinal decrease in unit cost per doubling of production quantity. For a manufactured item such as a wind energy system, a different learning curve may apply to materials, labor, sub-assemblies, etc., requiring a composite learning curve for the total system. At the present time, there is substantial uncertainty in the percentage value to use for the learning curve for WECS. However, whatever value is used, the net result will be to reduce the capital costs of WECS as additional units are produced. There is also the potential for additional reductions in capital costs through technology enhancements resulting from R and D. The effects of R and D are not included in the learning curves (JBF Scientific Corporation 1977a, p. 33).

WECS. From the six research projects reported by JBF Scientific Corporation (1977a) and shown in Appendix E, cost figures of both Honeywell and SWRI are relevant to this study, since these research efforts assess the same 220 W/m^2 wind machine designed by Boeing Vertol Company (Wiesner and Kisovec 1976). Capital costs for this wind machine of approximately 1 MW range from about $650 to $750/kW (1975 dollars).

These estimates are based on a 100-unit production level, which is equal to the 100 MW WECS capacity added to the DPC proposed plan. Capital costs will decrease when the number of wind machines manufactured increases, thereby partially offsetting the decreased break-even costs formed with higher WECS penetration levels. Adjusting for an annual inflation rate of about 7% during 1975-78, capital costs for the 220 W/m^2 wind machine of 1 MW capacity range from about $800 to $900/kW (January 1979 dollars).

These costs are to be compared with the break-even costs presented in Figure 23. This graph shows that if the annual fuel price increase during the period 1992 to 2020 equals or exceeds about 9%, WECS added in 1985 to the DPC proposed plan will be economically attractive.

The 90 W/m^2 wind machine has characteristics similar to the ERDA/NASA 100 kW (Mod-0) wind machine, Sandusky, Ohio. None of the megawatt-sized WECS reviewed by JBF Scientific Corporation (1977a) have rated power densities as low as 90 to 100 W/m^2. A 1 MW wind machine with a rated power density of 100 W/m^2 requires a rotor diameter of about 110 m (370 ft). The first three phases in the Federal Wind Energy Program, Mod-0 (Thomas and Richard 1977), Mod-0A (Robbins and Sholes 1977) and the Mod-1 (Barchet 1977), do not consider rotor diameters larger than about 60 m (200 ft). The Mod-2 wind machine program (Couch 1977) is designed to evaluate large machines suitable for wind regimes with an average annual wind speed of 6.2 m/sec at about 10 m height. Rotor diameters in the range of 90 to 150 m will be evaluated, which include rated power densities of about 90 to 100 W/m^2.

Based on a preliminary cost analysis of the Mod-2 (Couch 1977), a 90 W/m^2 wind machine in Rochester, Minnesota, will cost about $1,200/kW (January 1978 dollars), employing the same assumptions as those of JBF (1977a) for the six studies reviewed. These costs seem to be high, since smaller wind machines with similar characteristics cost < $1,000/kW. A comparison of this preliminary cost estimate and the break-even costs presented in Figure 24 shows that this type of WECS would be economically attractive, if fuel prices increase faster than 9 to 10%/yr (inflation included) during 1992-2020.

It has not been proven that megawatt scale wind machines will be cheaper than wind machines with capacities in the range of 10 to 100 kW. This may be particularly important for utilities like the Dairyland Power Cooperative, serving customers of which 45% are commercial farms and 50% are rural residential. To illustrate this point, the following WECS is assumed: 100 MW total capacity which consists of 2,857 wind machines with a capacity of 35 kW and a rated power density of 110 W/m^2 (slightly > 90 W/m^2

assumed for this study). Each of the 29 member cooperatives of the DPC will install 100 wind machines in groups of 10 to 20 machines, for example.

Since the average member cooperative has 2,250 commercial farms, an alternative system can be to choose one out of 23 farms for a wind machine site. It is assumed that the wind regime averaged over all locations will be similar to the one for the large megawatt scale system. Towers for these smaller machines are generally less than 60 m. Consequently, the choice of sites is critical.

The General Electric Wind Energy Mission Analysis (1977) contains cost estimates of 35 kW machines. These data are obtained by contacting vendors and obtaining quotes for various system components, assuming an order of 100 units. Using a learning curve of 90%, an order of about 2,900 wind machines will result in a cost of $740/kW (January 1979 dollars). When the cost of a WECS-utility interface of about $130/kW (Windworks 1978) and site-dependent costs of about $100/kW are added to these machine costs, the total capital cost becomes $970/kW (January 1979 dollars).

Due to the dispersed nature of this type of WECS, O and M costs will be higher than the 3% generally assumed for the megawatt scale WECS. An O and M estimate of 5% of capital cost, for example, means approximately $170,000 per member cooperative to operate and maintain 100 machines (January 1979 dollars). For example, a maintenance schedule of an annual check taking 1 day/machine and a major overhaul once in 5 yr taking about 1 week/machine, seems sufficient for this type of machine. A crew of 2 to 3 people, having technical skills similar to auto-mechanics, will need 40 weeks/yr for such a maintenance schedule.

Since the operation of wind machines can be fully automatic (Thomas and Richards 1977), an annual budget of $170,000/Co-op appears to be adequate. Benefits include the creation of new rural jobs. Figure 24 shows that a dispersed system appears to be economically attractive for DPC, provided that fuel prices increase at an annual rate equal to or exceeding 10%. This is basically the same conclusion as for the megawatt sized WECS.

Based on assumptions outlined in this paragraph, wind machines of the type assessed appear to be economically competitive, provided that fuel prices increase at a rate equal to or exceeding 9 or 10%/yr (inflation included) during the period 1992 to 2020. The DPC will save valuable fuels and money if wind machines are added in 1985 to the proposed expansion plan. It should be emphasized that uncertainties exist as to both capital and O and M costs of WECS. However, these uncertainties appear to be smaller than those in other sections of the electric utility system, e.g., the capital cost of new nuclear power plants.

FURTHER DISCUSSION OF THE ANALYSIS

A comparative analysis of alternative expansion plans of a utility contains numerous postulations that more or less influence the outcome of the analysis. Benefits of a WECS primarily consist of fuel savings (capacity credits not taken into account), with additional savings in O and M and energy purchases (Table 19). Since DPC coal- and nuclear-fired power plants meet almost all load and energy requirements, the discussion focuses on these generating units.

It generally has been argued that nuclear power plants have an economic advantage relative to coal-fired power plants due to low nuclear fuel costs that more than offset the higher nuclear capital costs. The assumptions made by DPC represent that point of view, which is reflected in the coal and nuclear fuel curves in Figure 19 and capacity factors in Figure 20. However, recent studies indicate that nuclear capital costs are rising sharply and are not exactly known.

Bupp and Derian (1978) in their recently published book, *Light Water, How the Nuclear Dream Dissolved*, argue that capital costs were almost anyone's guess in 1975, with over 100 LWR in operation or under construction. Some 20 yr after the first LWR began operating, cost has not stabilized. Learning has not yet occurred which is illustrated by a 1975 electricity production cost figure that is 50% higher than for the first non-turnkey plant. These authors further note that capital cost estimates have not become more accurate, with a factor two difference between the estimated and actual cost.

Throughout this period of many years, cost estimates were taken for facts by both government and industry, and they "shrugged off the repeated failure of nuclear power to match economic expectations as a fully understood and, hence, manageable aberration. Later, as the failures persisted, they dismissed them as somehow irrelevant because 'the same thing is true for coal'" (Bupp and Derian 1978, p. 81). Both authors and Montgomery and Quirk (1978) discuss the possible causes of cost increases in more detail. Mooz (1976) reports an average capital cost increase of $188/kW/yr during 1970 to 75. The capital cost of a new nuclear power plant, to be on-line in 1979 in New York State, is estimated at $1,400/kW (Komanoff 1977).

In light of these trends and uncertainties, capital cost estimates of nuclear power plants for the DPC may be too low by a factor of two (Table 9). But it is also possible that the DPC cost estimates of Tyrone are correct. The Tyrone unit is one of a group of five nuclear plants being designed as a Standardized Nuclear Power Plant System (SNUPPS). Western Wisconsin Utilities (1978) report that the cost estimates and design were developed in most cases in the time frame of early 1976 through 1977 "so that the plant design philosophy is reasonably representative of current regulations and licensing situation." If, on the other hand, environmental and safety factors continue to require significant changes in nuclear power plant design, cost stabilization due to learning may not occur.

Other factors contribute to the uncertain future of nuclear power. Siting nuclear power plants meets opposition by a growing section of the population in many industrialized societies. This opposition causes delays in power plant licensing and construction, as well as cost increases: additional interest during construction, inflationary effects on parts that are constructed later than anticipated, additional construction cost. Another factor is the continued opposition to the high voltage transmission lines that are necessary with highly centralized power production. Critics further argue that many costs related to nuclear power such as regulation, waste disposal, and some subsidies are not properly accounted for, which results in an underestimate of the true cost.

In additon to these uncertainties as to nuclear capital cost, the outlook on the availability of uranium ores does not seem better. Day (1975) calculates that cumulative demand of high-grade (> 500 ppm) uranium ore may exceed the projected uranium oxide reserves (at \$67.50/kg or \$30/lb of oxide) by the year 2000, employing the ERDA 1975 reserves estimates. Lieberman (1976) questions the ERDA reserves estimates and suggests a possible shortage of high-grade uranium ores in the late 1980s. Of course, lower grade ores could become available at higher prices of uranium oxides, but associated problems may make this option unacceptable. Day (1975), for example, calculates that with 70 ppm uranium ore, "to obtain an equivalent gross amount of electrical energy, it would be necessary to move roughly 2.3 times as large a volume of uranium ore as coal."

Even if such a scheme is economically feasible and environmentally acceptable, one wants to make sure that the net energy gain of an energy system is positive. The ratio between high-grade uranium ore reserves and cumulative demand will be small by the end of this century. Consequently, the nuclear fuel price is likely to rise significantly faster during the last part of this century and the beginning of the next century than the 7 to 8% annual increase (including inflation) assumed by DPC for the period 1985-91. An annual increase of at least 10% seems more likely during the period 1991-2019 considered in this study.

Whether nuclear power plants will be cheaper than coal-fired plants also depends upon the development costs associated with burning coal. The increased reliance on coal, as envisioned by many policymakers, will increase both capital cost of the power plants and the price of coal. Ebasco (1977) reports that the price of coal for electric utilities in the north-central region has increased from about 35¢/10^6 BTU in 1973 to about 80¢/10^6 BTU in 1976, or roughly 25%/yr. Although many long-term contracts have not been influenced by these price increases, future contracts will be.

A recent report of the National Academy of Sciences (1975) on mineral resources and the environment describes a large number of measures that will be necessary to maintain or improve health and environmental conditions associated with the increased usage of coal. The Academy cites land reclamation, increased safety for coal miners, and air pollution control as major problems. Some of these problems can be solved, most of them can be reduced, but many cannot be eliminated even if large sums of money are spent.

The Academy states that "health costs related to the pollution from a large coal-fired plant located near a metropolis may be as high as the cost of fuel required for generating the electricity." The combination of increased cost for land reclamation, transportation system's renewal and the (partial) internalization of presently external health-related cost will most likely increase the coal price and costs of coal-fired power plants much faster than the general inflation rate.

Uncertainties in the costs of wind machines seem smaller than those of coal- and nuclear-fired power plants. Furthermore, the uncertainties in WECS costs are primarily due to the as yet unknown effects of mass-producing wind machines. It can be argued that industrialized societies have a much better record of mass-producing relatively simple new technologies at unexpectedly low cost than their record of controlling cost and solving problems of complex technologies requiring an increasing role of national and international governmental institutions (Weinberg and Hardin 1976; Weinberg 1977; Von Hippel and Williams 1977; Elgin and Bushnell 1977; Bupp and Derian 1978). Thus, the range in capital costs of WECS does not introduce larger uncertainties than commonly occur in the analysis of electric utility expansion plans.

The expected increase in the price of fuels has a significant influence on the break-even capital cost of WECS, as shown in Figures 23 and 24. Fuel price increases during the period 1991-2019 in excess of 9 or 10% (inflation included) seem likely. This represents only a slight increase in the fuel price increases during 1985-91 assumed by the DPC (7% for coal, 7 to 8% for nuclear fuel, see Table 14). This study indicates that the WECS added to the DPC proposed plan will be economically attractive if coal and nuclear fuel prices increase faster than 9% during the period 1992 to 2019.

Federal R and D energy programs influence the type and costs of technologies employed today and continue to influence the technologies and public spending in the future. An emphasis on a given technology precludes spending monies on alternatives within the R and D budget. Thus, R and D priorities form in some ways a prognosis of what is to come, even though positive results are not automatically produced when more money is spent (Steinhart 1974; O'Leary 1975). Cone et al. (1978) indicate that there are "two apparent rationales for (energy production) incentives: (1) promotion of a new technolgy during early stages, and (2) payment of the difference between the value of an activity to the private sector and its value to the public sector. The support of nuclear energy represents an example of the first justification. Examples of the second are rural electrification (REA), economic development (TVA), flood control (dams), and price controls (oil, gas, and coal)." The same authors estimate that the federal government has expended about $\$130 \times 10^9$ since 1918 to stimulate energy production. Roughly 65% of these incentives fall in the categories of taxation and disbursements. Incentives without clearly quantifiable costs, such as the Price-Anderson liability indemnification for nuclear power, are identified. Solar energy has received little R and D money during this time period. Data presented at 1977 Solar Energy hearings, Senate Select Committee on Small Business, show 1975 cumulative federal expenditures of \$0.069 x 10^9 for solar energy (of which wind is a small fraction) and \$5.25 x 10^9 for nuclear fission, roughly a factor 75 difference. Recently, expenditures for solar energy have been increased but are still lower than those for both fossil fuels and nuclear technologies.

Incentives for WECS-utility applications could make a significant difference to the economic feasibility of WECS. Figure 23 shows that a property tax exemption for a WECS will increase the break-even capital cost by about 20%. Another effective measure is the availability of low interest loans similar to REA programs. For example, a 7% instead of 9% interest rate for DPC will increase the break-even cost of the 220 W/m^2 wind machine by about 35% (using a fuel price increase of 7%). Available wind data are not sufficient to assess the full potential of WECS. A well-designed wind energy survey in close cooperation with utilities is needed with funding by the federal government. Furthermore, the present technology development effort of the DOE Wind Energy Branch will presumably result in lower wind machine costs. Other effective incentives may exist.

It is frequently argued that continued growth in centralized energy supply facilities is necessary to create new employment and maintain or increase the high standard of living. People who promote decentralized solar energy systems are often portrayed as being against workers and the poor. However, recent studies indicate that solar energy technologies may be 2 to 4 times as labor intensive as nuclear fission or coal-fired generating units (Monroe et al. 1976; Laitner 1976). Grossman and Daneker (1977) estimate that solar technologies require many more tradespeople per professional scientist or technician than does nuclear power: for nuclear power the ratio is about 2:1, for solar it is 9:1. These solar-related jobs will become available closer to home due to the dispersed nature of the technology and require less training, which implies that more people will qualify.

My study analyzes WECS as an addition to the proposed plan of the DPC, so employment offered by the DPC will increase. A crew of 2 to 3 people/member cooperative may be needed to operate and maintain this WECS so such a scheme would mean a 10% increase in jobs per member cooperative. Large megawatt wind systems will presumably offer a somewhat lower number of jobs provided by the utility. In addition, the manufacturing and installation of WECS will require labor input. According to the studies cited, these labor gains more than compensate job reductions in the coal and nuclear industries.

Another aspect to be considered is the rate of implementing a WECS manufacturing and installation program. The contribution of solar energy technologies to meet the nation's energy demands is generally estimated to be less than 10% by the year 2000. However, there are several reasons why these low estimates of solar technologies may exist. Some are quoted here from Grossman and Daneker (1977):

> Senator Gaylord Nelson (D-Wis.), noting that these solar projection studies were performed by companies heavily invested in nuclear power, coal, natural gas, and oil, commented:
>
> The suspicion is unavoidable that these and other absurdly low estimates of the solar contribution during the next 25 years are not of what the estimators think the country could do if it put forward anything like the money and effort that went into nuclear development or moonshots, but rather what they hope the country will do.
>
> The FEA Project Independence Task Force found that among "factors which have inhibited" the growth of solar systems were: (1) a lack of federal or private industry interest, and (2) underpriced, taxpayer subsidized fuels.
>
> Government officials frequently say that modest sums appropriated for solar energy are as much as can be prudently spent, given the state of the art. They say that a "new" industry can progress only a little at a time. But on some occasions when this country needed vigorous action, even the federal bureaucracies and private industry responded. For example, when specialized aircraft were needed during World War II, the fledgling aircraft industry was able to increase production from 3,623 in 1938 to 96,318 in 1944.
>
> The FEA concluded:
>
> It is assumed that wind energy systems are not more difficult and probably far less difficult to produce than World War II aircraft.

Thus, the WECS capacities of 100, 200, or 400 MW to be added to the DPC system in 1985 appear to be within the potential of the United States industrial manufacturing capacity.

Finally, it should be emphasized that an economic analysis is only one input out of a large number of aspects to be evaluated in public decisionmaking. Policy decisions are strongly influenced by the notion whether a certain technology is economic or uneconomic. Or in other words, whether the technology considered can earn an adequate profit or not. But, as Schumacher (1973) states:

> Society, or a group or an individual within society, may decide to hang on to an activity or asset for non-economic reasons - social, aesthetic, moral, or political - but this does in no way alter its uneconomic character. The judgement of economics, in other words is an extremely fragmentary judgement; out of the large number of aspects which in real life have to be seen and judged together before a decision can be taken, economics supplies only one - whether a thing yeilds a money profit to those who undertake it or not.

The previous and following paragraphs outline advantages of the use of solar resources in comparison with the depletable stock resources and centralized energy systems. Many of these issues are clearly outside the realm of economics. Therefore, the often used economic benefit and cost analysis of fossil fuel and nuclear power versus wind and solar power as a principal decisionmaking tool can be highly misleading. Or, as Eckstein argues, a benefit-cost analysis is only suited to examine choice situations if:

(1) The nature of the cost is reasonably uniform
(2) The benefits are uniform on the conceptional level
(3) The lifespan of the projects is about the same order of magnitude
(4) Both projects have about the same capital intensiveness
(5) Risk should be about equal
(6) The level of available information should be about equal

In other words, the technique is useful to examine choice situations where the changes are marginal (Steiner 1969). These conditions are not met in the choice set of coal and nuclear fuels versus solar energy. Furthermore, a benefit-cost analysis does not take into account considerations such as who is receiving the benefits and paying the costs. The net-benefit analysis as used in this study is, therefore, useful in a limited way. The analysis provides an indication whether certain economic incentives are necessary to make the technology considered economically attractive for private companies or citizens.

SOCIOENVIRONMENTAL CONSIDERATIONS

WECS have positive and possibly some negative impacts when these systems are integrated with electric utilities. A few socioenvironmental aspects will be briefly discussed.

Since the WECS analyzed is added to the proposed expansion plan without taking any capacity credits into account, all power plants are assumed to be built as planned regardless of the capacity of the WECS. Therefore, socio-environmental benefits mainly pertain to the fossil and nuclear fuel consumption.

Significant amounts of fuel are being displaced by the WECS. Consequently, problems related to burning coal are reduced: land reclamation in coal strip-mine areas (Anthrop 1978), effects of burning fossil fuels on the global climate (Kellog 1978), coal mining hazards and negative health effects (NAS 1975). The same is true for the different components of the nuclear fuel cycle: uranium mining, milling, enrichment, fabrication, burning and waste disposal (Holdren 1974; Hayes 1976; NCC 1976; Caputo 1977; Flowers 1978).

Wind energy systems have been described as being an intermediate technology (Schumacher 1973), soft technology (Lovins 1976), or a democratic technology (Mumford 1963). This type of technology has most of the following characteristics:

(1) Small scale, decentralized; energy supply is an aggregate of many small distributions (vs. centralized, MEGA-machine); adapted to local circumstances; matching of energy quality

(2) Techniques are locally controlled; protection against arbitrary external controls; no centralized management

(3) Technical deversity and adaptability give a good prospect to stability under a wide range of conditions (in contrast to complicated large-scale technologies that will fail if all conditions are not met all the time, indefinitely)

(4) The use of renewable (flow) resources or local stock resources

(5) Risks of success and failure are distributed

(6) Environmental risks are low, mostly reversible, and predictable
(7) Costs and benefits of system are for a large part to the one who chooses

(8) Flexibility because of short lead times and incremental nature, so rapid responses are possible in times of uncertainties.

Although a WECS interconnected to the utility systems generally needs to be managed to a certain extent on a utility-wide scale or possibly even on a power-poolwide scale, it does not need a supernational and international management scheme as does nuclear power. Installation, operation, and maintenance functions of WECS can be performed by the member cooperatives. This will most likely increase public access to the decisionmakers and the level of public participation in decisionmaking. Other benefits may occur when these less complex systems are introduced (Elgin and Bushnell 1977; Hayes 1977; Flowers 1978).

Several environmental impacts of wind machines are to be expected. Sengupte and Senior (1977) report possible interference with TV reception by wind machines; cable TV may be necessary in areas near wind machine sites. Rogers (1977) presents preliminary results indicatig no significant microclimate effects of wind mahines of about 100-kW capacity. Rogers et al. (1976) conclude that land requirements are minimal and compatible with many other land uses and that the 100-kW ERDA/NASA wind machine is not a high risk to airborne fauna, "including the most vulnerable nighttime-migrating song birds." The same authors state that if wind machines in the future exceed 150-m height, bird/blade collisions may become much more frequent. Thus, siting has to be done with more care when machine size increases. Sound levels generated by the 100-kW wind machine do not disturb humans and wildlife. Some of these findings may change with other wind machines.

At present, it is virtually impossible to evaluate visual pollution of wind machines. Ferber (1977) reports the results of a survey indicating that people overwhelmingly prefer Dutch-type wind machines. Besides, towers of columnar nature and attractive color design may play an important role, too. Wind machine "farms" will most likely be less positively judged than individual wind machines.

CONCLUDING REMARKS

This analysis indicates that wind machines added in 1985 to the DPC proposed expansion plan will save both valuable fuels and money. Wind machines may be too expensive only if fuel prices increase at a lower annual rate than 9% (including inflation) during the period 1992 to 2019 or if wind machine cost estimates are too optimistic. Uncertainties in the cost of wind energy systems appear to be smaller than those in the coal and nuclear alternatives. Certain incentives could play an important role in promoting the installation of a wind energy conversion system. A property tax exemption would increase the break-even capital cost of a WECS by about 20%. The availability of loans with interest rates of 7% instead of 9% would increase the WECS break-even cost by about 35%.

SECTION 8

THE APPLICATION OF WECS TO AN ELECTRIC UTILITY IN COMBINATION WITH ACTIVE LOAD CONTROL AND HEAT STORAGE SYSTEMS: THE CASE OF THE DAIRYLAND POWER COOPERATIVE

INTRODUCTION

The method of analysis described in Section 7 consists of a standard utility production costs and reliability analysis, whereby a WECS is an integral part of the generating mix.

The objective of the analysis presented here is to compare a WECS plus a pre-identified controlled load to conventional combustion turbines that serve as peak-load generators. This type of analysis basically evaluates the potential of a WECS as a peak-load generator, in addition to the savings in production costs. The positive correlation between wind availability and load, plus a significant storage-heater/cooler load, make "peak shaving" possible. Synchronous hourly load and wind speed data for the period 1969-73 are used in this analysis.

LOAD CONTROL, ENERGY QUALITY, AND ENERGY STORAGE SYSTEMS

Electricity generated during peak-load hours is expensive due to the use of expensive fuels (gas, oil) and high capital cost per kWh generated. The latter is a result of the underutilization of peak-load generators, even though the capital cost per kW peak generator is low. Stern and Schoengold (1977) estimate the operating cost of generating the top 10% of the load at 1.7¢/kWh and annualized capital cost at 30¢/kWh (1975 average system cost 0.8 and 0.4¢/kWh, respectively). A decrease in the growth of peak demand and in the use of expensive fuels will help reduce the rise in the cost of electricity. Since the retail electricity price in real terms (deflated to remove the effects of inflation) decreased until the late 1960s (Hirst and Carney 1977), the increase in demand has traditionally been taken for granted. Recently, however, electricity prices have sharply increased and more attention is paid to possible reduction in growth.

Load control techniques and energy storage systems can be used by a utility to flatten the load curve and to increase average load factors.

Stern and Schoengold (1977) state:

> Load control gives the utility the flexibility to drop or defer prespecified loads during times of high marginal operating costs or high probability of system failure, while continuing to provide for designated "must serve" loads. This flexibility allows for more efficient use of generating capability. It also lessens the need for future facilities and serves as a damper on the impacts of load forecasting error.

There are two major load control strategies that can be used by a utility dispatcher:

(1) To shed loads that are considered of minimal essentialness during periods of unusual economies or high probability of system failure (loss of load); or

(2) To shift loads on a regular basis to a time when they can be more economically provided for.

Loads suitable for applications in category 1 are primarily in the industrial and large commercial sectors. Loads in the residential and small commercial sectors can be shifted on a daily basis: water and space heating, air conditioning, refrigeration, ventilation, and certain lighting. Loads of category 1 include those in category 2 on an emergency basis. Table 21 shows types of load that can be controlled.

Load control technology has been successfully used in western Europe for many years. Asbury and Kouvalis (1976) report important flattening of daily load curves. Sosin (1977) states that the storage-heater load in Britain has increased tremendously: 600 MW in 1962-63 to 13,600 in 1973-74. The average daily load factor has changed during the same period from 72 to 86%.

In the recent literature on the second law of thermodynamics efficiency considerations, attention is focused on the quality of energy needs and energy resources (American Physical Society 1975). From this perspective, organized coherent motion is highest quality energy, next electricity, then very high temperature heat or very low temperature cooling, whereas heat as a temperature close to the ambient temperature is degraded energy. Table 22 shows the end use of energy and indicates that a large percentage of the energy usage is of low quality, if transportation is excluded. This is particularly true for residential and commercial energy use, and to a much lesser extent for the industrial sector.

Energy quality differences can also be recognized between the energy resources. Direct solar energy delivers heat of relatively low quality (unless sophisticated collectors are used). Conversion of this heat energy into work or electricity is possible but with a loss of part of that energy.

TABLE 21. SOME MARKETS FOR OFF-PEAK ELECTRICITY USE (GORDIAN ASSOCIATES 1974)

THERMAL COMFORT

Storage Heating
  residential, commercial, institutional, industrial, transportation
Air Conditioning

INDUSTRIAL MOTIVE POWER

Refrigeration for cold storage or ice making
Pumping water for supply or drainage
Grinding rock, chocolate, cereals, etc.
Mixing

INDUSTRIAL PROCESS HEATING

Pottery firing
Vitreous enameling
Annealing
Melting and holding
Stress relieving
Billet heating
Anodizing
Drying

A windmill of a relatively simple design delivers high-quality energy. Conversion to electricity or heat is relatively simple with hardly any loss of energy. The same is true for hydropower. High second law efficiencies are obtained when the quality of the energy source and the energy needs are matched (American Physical Society 1975). However, one may want to use wind-generated electricity (high quality) for space or water heating (low-quality energy needs) to save fuel oil and natural gas.

Commercial farms and rural residents have largely low-quality energy needs and comprise 95% of DPC's customers. Energy use data (transportation not included) for an average Wisconsin household in 1974 show that 78% of the energy is used for heating and cooling purposes (Smith and Jenkins 1974). Approximately 65% of the energy consumption at a typical Wisconsin dairy farm is used for water heating and milk cooling (DeWinkel and Steinhart 1976). A thermal energy source/storage system of low to moderate temperature suffices for this type of load. Storage systems that are designed to deliver electricity back to the grid are not needed for most of the residential, commercial, and farm loads.

TABLE 22. END USE OF ENERGY IN THE UNITED STATES IN 1968: CLASSIFICATION BY THERMODYNAMIC QUALITY OF THE ENERGY (STANFORD RESEARCH INSTITUTE 1972 ARRANGED BY AMERICAN PHYSICAL SOCIETY 1975)

	Energy equivalent of fuel consumed (10^{15} BTU)	% of total fuel	% of total electricity allocated to sector
Residential/commercial space conditioning and other low-temperature energy (lowest-quality energy)	16.4	27.0	26.0
Industrial process steam and residential/commercial cooking (low-quality energy)	10.9	18.0	3.5*
Industrial direct heat (higher-quality energy)	6.9	11.5	2.0**
Miscellaneous, mostly very high-quality energy, such as electric drive, lighting, and electrochemical processes	8.0	13.2	68.0
Transportation (highest-quality energy: work = "infinite-temperature" energy)	15.0	24.8	0.4
Feedstock***	3.3	5.5	--
TOTAL	60.5	100.0	100.0

* This is all cooking; assumed zero use of electricity for generating process steam.

** The SRI tables show that less than 2.6% of electricity was used for industrial heat in 1968, but do not give an exact figure.

*** Feedstock is fuel used as raw material rather than as fuel.

It appears, therefore, useful to focus on thermal storage devices in combination with the wind electric system because:

(1) Thermal devices are relatively cheap

(2) Thermal devices are suitable for dispersed storage systems like in households and on farms

(3) Utilities in Europe have an extensive experience with these centrally controlled devices

(4) American utilities including the DPC are experimenting with these thermal devices and central control systems.

Note that the temperature of the storage medium with a WECS can normally be much higher than with a solar flat plate collector system, which makes absorption air conditioning relatively simple.

THE IMPORTANCE OF LOW-QUALITY ENERGY USE TO THE DAIRYLAND POWER COOPERATIVE SYSTEM

Table 23 displays the estimated 1976 number of DPC members by consumer classification. Rural residents and dairy farms are the two largest groups of members. The following discussion deals briefly with dairy farms, and focuses on the residential sector.

TABLE 23. DAIRYLAND POWER COOPERATIVE ESTIMATED 1976 NUMBER OF MEMBERS BY CONSUMER CLASSIFICATIONS

Classification	Consumers
Dairy farm	41,900
Other farm	26,750
Rural residential	75,173
Commercial & industrial	3,720
Sales for resale	27
Other*	1,850
Total	149,420

*Includes public buildings, street lighting, and irrigation.

Electricity consumption on a 1976 average dairy farm is approximately 500 kWh/cow/yr. A highly mechanized large dairy farm may use as much as 1,000 kWh/cow/yr (DeWinkel and Steinhart 1976). Using the electricity use figure for an average farm and the estimated 865,000 dairy cows in the DPC service area (Western Wisconsin Utilities 1978) gives an estimated energy consumption of 432,500 MWh/yr. If the trend of fewer but larger dairy farms continues, electricity use on dairy farms may double. Approximately 120 kWh/cow/yr are used for milk cooling at both types of farms, while 50 and 160 kWh/cow/yr are used for water heating at the average and large dairy farm, respectively. The introduction of a heat pump system between the milk cooler and water heater eliminates the energy consumption for water heating (Mueller 1976). This leaves about 120 kWh/cow/yr for milk cooling, which can be controlled if thermal energy storage systems combined with cooling systems are installed. Assuming a 2 to 4 kW load per milk cooling system at each of the 42,000 dairy farms in 1975-77, roughly 80 to 160 MW of the total DPC load could be controlled. Since this load contributes to the daily peak, a significant flattening of the daily load curve can be accomplished by installing these systems.

Solar heating systems would also be useful for this part of the dairy operation if solar absorption cooling systems become technically and economically attractive. Although absorption cooling systems are not yet readily available, this technology will most likely be available in the early 1980s (Energy Research and Development Administration 1976) and could have a significant impact on the load of the DPC. However, DPC has not yet included these considerations in its recent load forecasts. The DPC conservation and load management programs focus on residential space and water heating and efficiency improvements of motors, refrigerators, milk coolers, and compressors.

The DPC system is very weather sensitive due to a substantial number of electrically heated homes and buildings. New electrically heated homes and buildings contribute directly to the need for increased capacity. For each newly built building, up to about 12 kW of capacity has to be added to the peak capacity of the DPC system. Table 24 indicates the capacity of the different heating systems. Note that the heat pumps presently installed do not compare favorably with the other systems.

Figure 25 shows the rapid growth of the number of electrically heated houses in the DPC system. Electrically heated buildings roughly tripled in numbers from 1969 to 1975. If this trend continues during the next 7 yr, about 50,000 buildings will be heated by electricity from the DPC. Figure 25 also shows the percentage of saturation based on the total membership of the DPC and two projections of saturation levels of electrical heating for the United States (Federal Power Commission 1970; Makhijani and Lichtenberg 1973). The actual DPC 1975 level of saturation is lower than the level predicted for the United States, but the rate of growth is higher.

Figure 26 indicates some of the possible futures. Total winter peak demand for the total DPC system and the winter peak demand due to electric heating only are given up to 1976. Actual heating peak demand was estimated

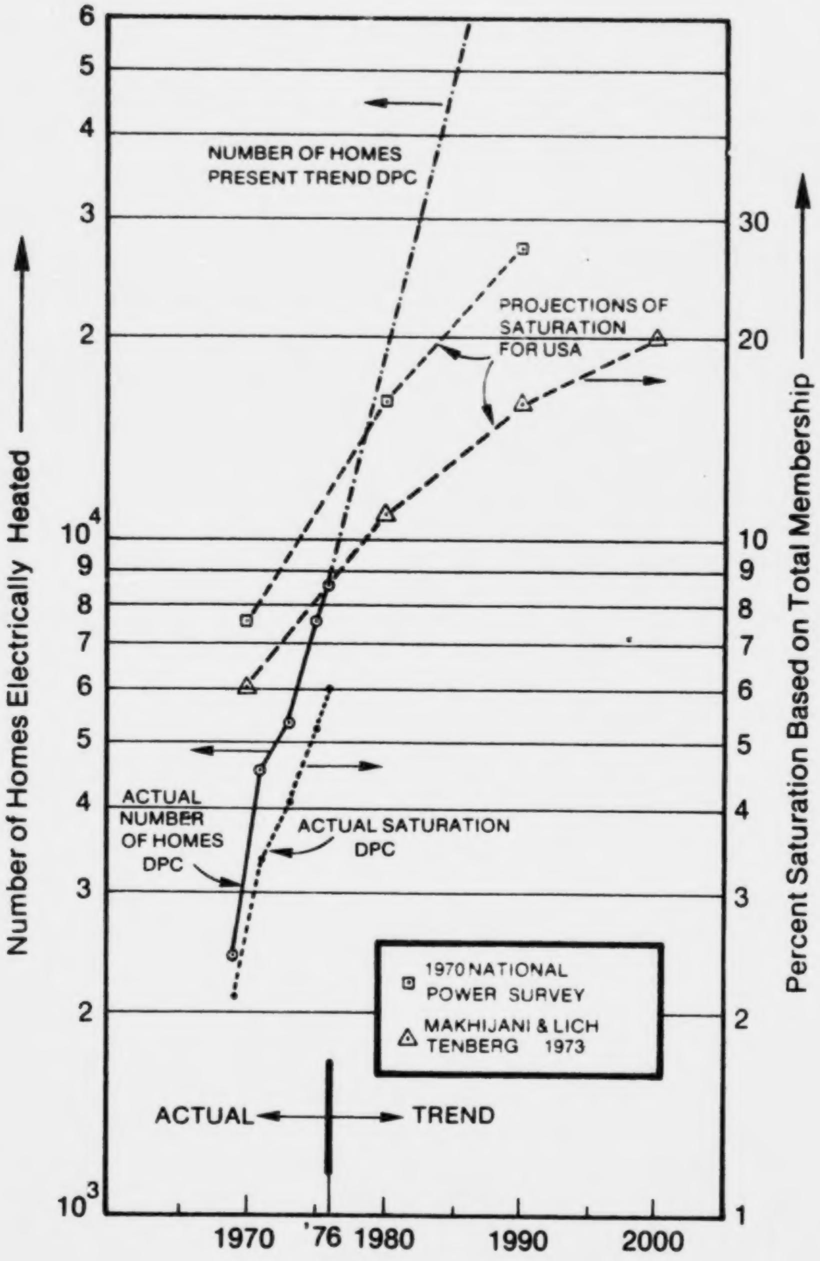

Figure 25. Electrically heated homes, Dairyland Power Cooperative.

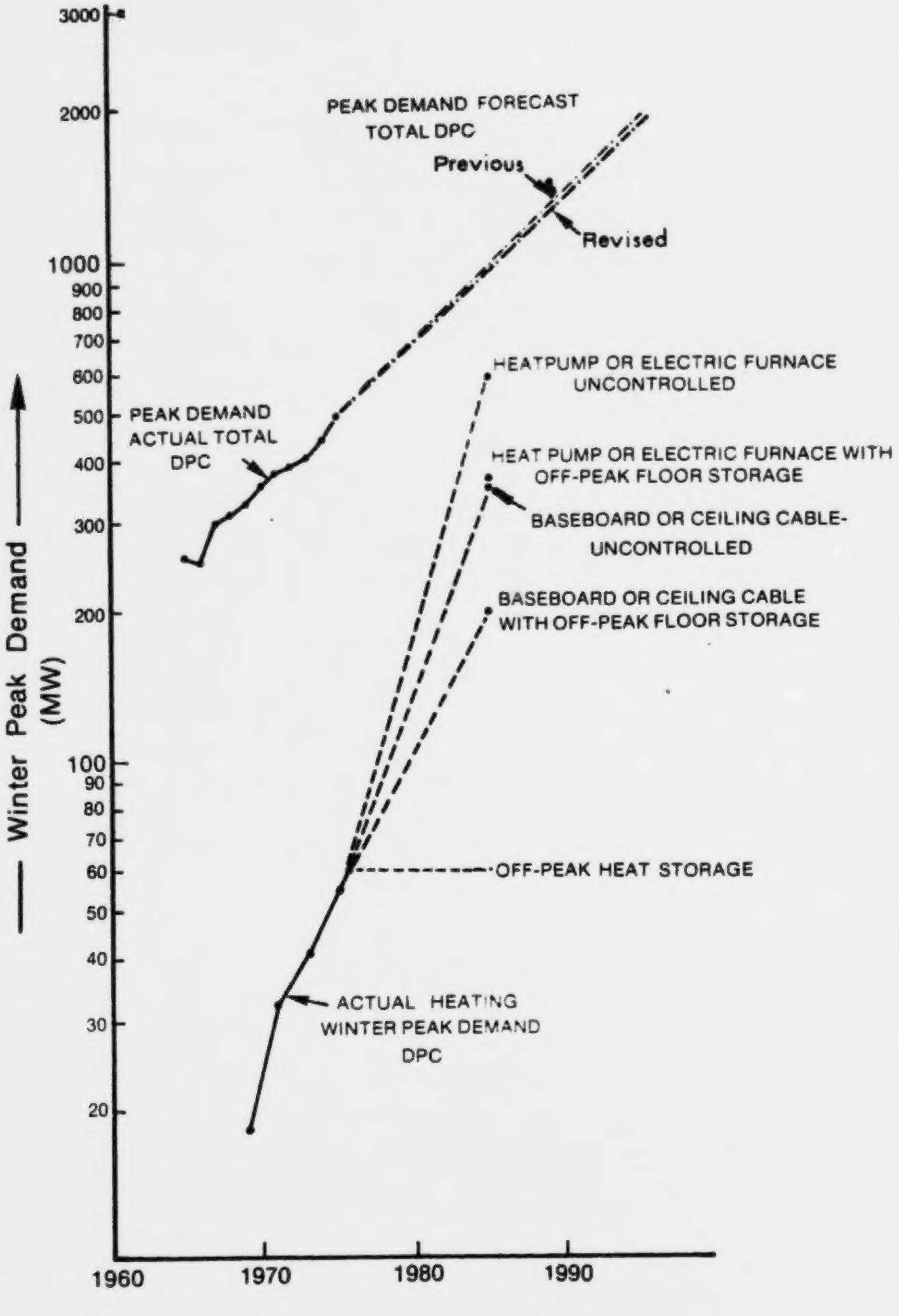

Figure 26. Total winter peak demand and peak demand due to electric heating only for the period 1969 to 76, and values for electric heat demand for 1976 to 85.

at about 11% of total peak demand in 1976. The values for heating peak demand from 1976 to 85 were computed from the peak-demand data in kW from Table 24 and the "number of homes present trend DPC" line of Figure 25. The values range from 61 MW if all new electrically heated buildings would have off-peak heat storage, to 600 MW if uncontrolled heat pumps or electric furnaces would be installed. Some alternative heating systems result in values between the extremes, and other heating systems can undoubtedly be found. As can be seen from Figure 26, if present trends continue for only a relatively short period of 10 yr, the consequences for the DPC system could become severe.

TABLE 24. ANNUAL DEMAND AND ENERGY REQUIREMENTS FOR VARIOUS TYPES OF ELECTRIC HEAT IN AVERAGE HOMES. (DAIRYLAND POWER COOPERATIVE, 1975 ELECTRIC HOME HEATING STUDY

	Peak demand (kW)*		Annual energy (MWh)	
	At residence	Net at plant	At residence	Net at plant
Baseboard or ceiling cable (uncontrolled)	6.3	7.1	16.0	18.1
Baseboard or ceiling cable (with off-peak floor storage)	3.5	4.0	25	28.3
Heat pump or electric furnace (uncontrolled)	10.5	11.9	21.5	24.4
Heat pump or electric furnace (with off-peak floor storage)	6.5	7.4	28.5	32.2
Off-peak heat storage	0	0	17	19.2

*Addition to peak demand at the time of Dairyland's peak load.

Total system peak demand forecast is shown in Figure 26 as given in the 1976 Advance Plan (Dairyland Power Cooperative 1976b) and as reported in the Revised 1976 Advance Plan (Western Wisconsin Utilities 1978). The DPC has made the following assumptions for the revision of its load forecast (see Table 25):

Table 25. DAIRYLAND POWER COOPERATIVE TOTAL SYSTEMS PEAK DEMAND FORECAST REVISIONS TO FORECAST DEMAND IN MW (WESTERN WISCONSIN UTILITIES 1978, SUPPLEMENT TABLE 1-6)

		Forecast modifications					
Year	Present forecast	Energy substitution (+)	Conservation (-)	Efficiency improvements (-)	Rate structure (-)	Load management (-)	Revised forecast
1977	580	7.5	3.6	--	0.1	--	584
1978	625	15.8	7.5	--	2.4	--	631
1979	670	24.1	11.5	--	3.5	--	679
1980	718	32.5	15.4	1	5.4	10	719
1981	769	40.9	19.4	3	7.2	23	755
1982	825	49.4	23.4	5	9.7	55.7	781
1983	884	58.0	27.5	7	12.5	58.3	837
1984	948	66.6	31.6	9	14.9	61.0	898
1985	1016	75.9	33.9	12	17.7	64.0	964
1990	1432	124	46.2	32	39.7	77.7	1360
1995	2008	175	60.1	64	66.1	92.5	1900

(1) Energy substitution: 35 and not 20% of new members will choose electric heating. Ten percent of the roughly 3,000 heating systems to be replaced annually will either be an electric furnace or heat pump. This results in additions of respectively 41 and 35 MW in 1985.

(2) Conservation: 75% of all new electrically heated houses will be energy efficient and underinsulated homes will be retrofitted. This results in 25% savings or 34 MW in 1985.

(3) Improved efficiency in motors, refrigera-tors, milk cooler, etc. results in a 0.2% or 12 MW savings in 1985.

(4) Rate structure will encourage off-peak space and water heating. It is assumed that by 1984, 10% of the new electrically heated homes will have off-peak space heating systems (it is not known why this was lower than 14% in 1976). The 25% of new and replacement water heaters will be suitable for off-peak operation; this results, respectively, in 8 and 10 MW savings by 1985.

(5) Load control will result in a 35 MW reduction in electric heat and a 29 MW reduction in hot water heating.

Trends cited by DPC will result in an electric heating peak demand of about 250 MW in the year 1985, as shown in Figure 26. This estimate includes the effect of off-peak heating systems, which represents roughly 14% of 1976 new electrically heated homes. DPC does not predict a higher off-peak heating percentage before the late 1980s. Even with the proposed energy conservation and load control measures, winter heating peak demand in 1985 may still be as high as 180 MW (250-34-35=181 MW), which means a tripling from 1976-85 or an annual growth rate of about 13%. If this trend continues, heating peak demand will increase from about 11% of total peak demand in 1976 to 19% in 1985. It is realized that trend projection may result in estimates that are significantly too high or too low in times of uncertainty.

This brief discussion of some aspects of the DPC load characteristics is not meant to be a thorough analysis of the load forecast. Rather, the arguments presented reflect that:

(1) A growing percentage of the DPC electricity and generating capacity is designated for low-quality energy tasks. This results in a wasteful utilization of electricity, since the quality of the energy source (high) and need (low) do not match. Alternatives such as total energy systems and solar systems may, therefore, be applicable.

(2) The growth in the low-quality energy load makes load control and dispersed thermal energy storage system possible and necessary. Although the DPC estimated load that can be controlled by the year

1985 is significant, stronger incentives and rules may be desirable to reduce the growth in the winter peak load. Note that since the capacity of an off-peak heating system has to be twice as large as that of a conventional system (only 8 h to charge the storage device), the number of off-peak heating systems to be connected to the grid is limited. Therefore, load control is necessary.

(3) The high potential of load control, thermal storage systems, and the continuing weather sensitivity of the DPC winter peaking system improves WECS' technical and economic feasibility. If future WECS generate a significant percentage of the DPC total electricity production, a low second law efficiency of electric heating systems may become acceptable. In addition, electric backup for solar heating systems may turn out to be more attractive.

THE METHOD OF ANALYSIS

Figure 27 contains a flow chart of the major components of this method of analysis, whereas Figure 28 displays a schematic presentation of the daily operations regarding the WECS, load control, and storage water heating systems.

The wind speed observation sites as well as the type of wind machines employed for this analysis are the same as those reported in Section 7. It was assumed that the WECS consists of wind machines equally spread over the three locations near Rochester, Mason City, and Waterloo. Annual average capacity factors at the three locations for the two wind machines with rated power densities of 90 and 220 W/m^2 range from 0.38 to 0.66 at 60-m height (Table 5). Height adjustments were made by using the 1/7-power law. The annual average capacity factor for the array of wind machines is 0.58 for the 90 W/m^2 wind machine and 0.41 for the 220 W/m^2 wind machine.

The average demand per hot water heater is estimated at about 0.7 kW (Leifer 1978: personal communication; Schoengold 1978: personal communication). Two values of WECS capacity per controlled water heater are assumed: 2 and 3 kW, or, respectively, 2.86 and 4.29 kW of WECS/kW of controlled load. A higher value of the WECS-controlled-load ratio means a more dominant role of the WECS. This results in a decreasing reliability to meet the peak load due to the variability in the wind and the practically zero forced outage rate (FOR) of load control technology.

It was assumed that the top 15% of DPC's load has to be met by peak-load generators. For the period 1969-73 considered in this study, this peak-load is reached roughly 1,000 times/yr (Tables 26 and 27). This 15% of total load peak-load range increases from 51 MW in 1969 to about 68 MW in 1973. The peak-load range is adjusted for each month by taking the top 15% of the monthly peak for each year. The WECS capacity is set at 1, 1.33, and

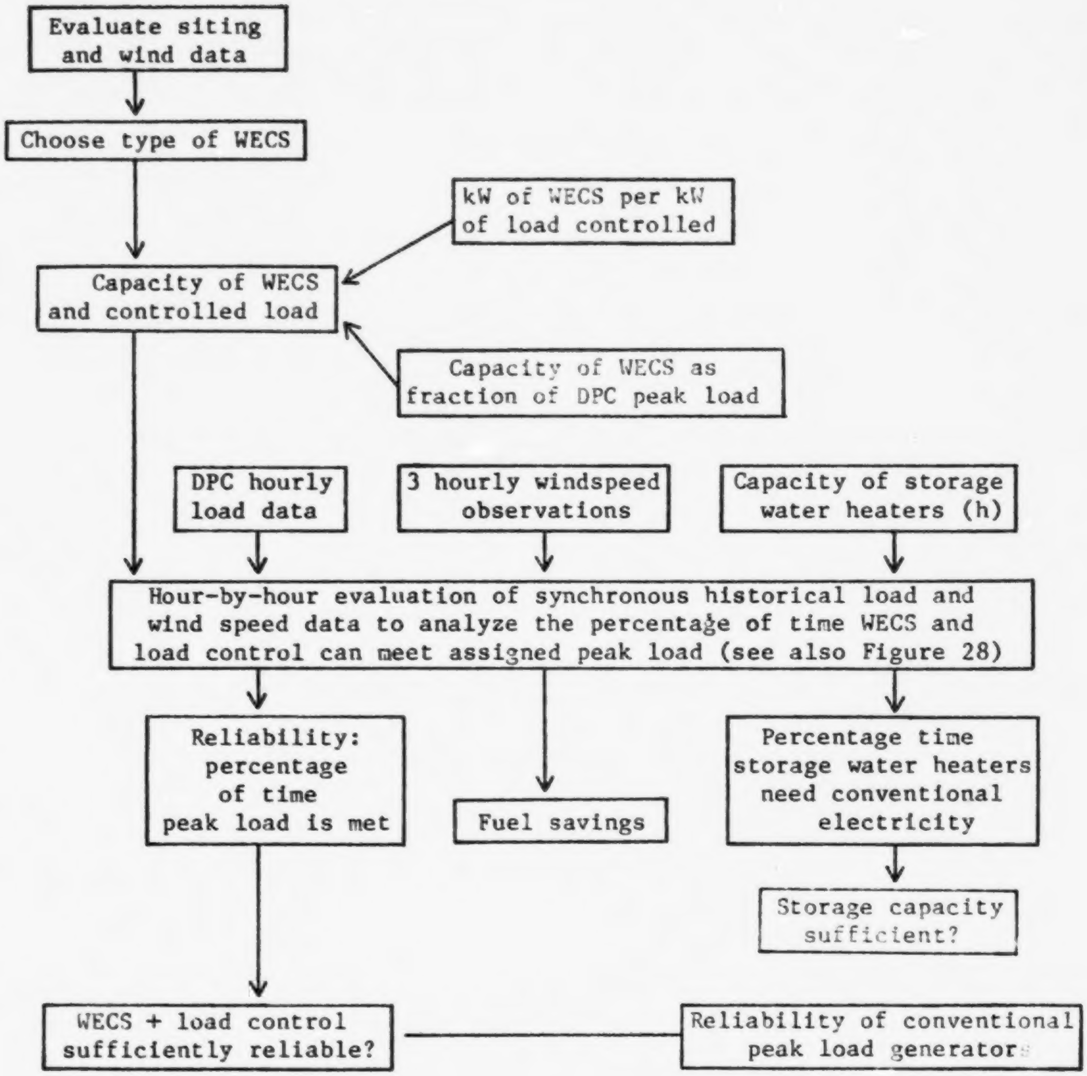
Evaluate siting and wind data
Choose type of WECS
kW of WECS per kW of load controlled
Capacity of WECS and controlled load
Capacity of WECS as fraction of DPC peak load
DPC hourly load data
3 hourly windspeed observations
Capacity of storage water heaters (h)
Hour-by-hour evaluation of synchronous historical load and wind speed data to analyze the percentage of time WECS and load control can meet assigned peak load (see also Figure 28)
Reliability: percentage of time peak load is met
Fuel savings
Percentage time storage water heaters need conventional electricity
Storage capacity sufficient?
WECS + load control sufficiently reliable?
Reliability of conventional peak load generators

Figure 27. Flow chart of the major components of the analysis.

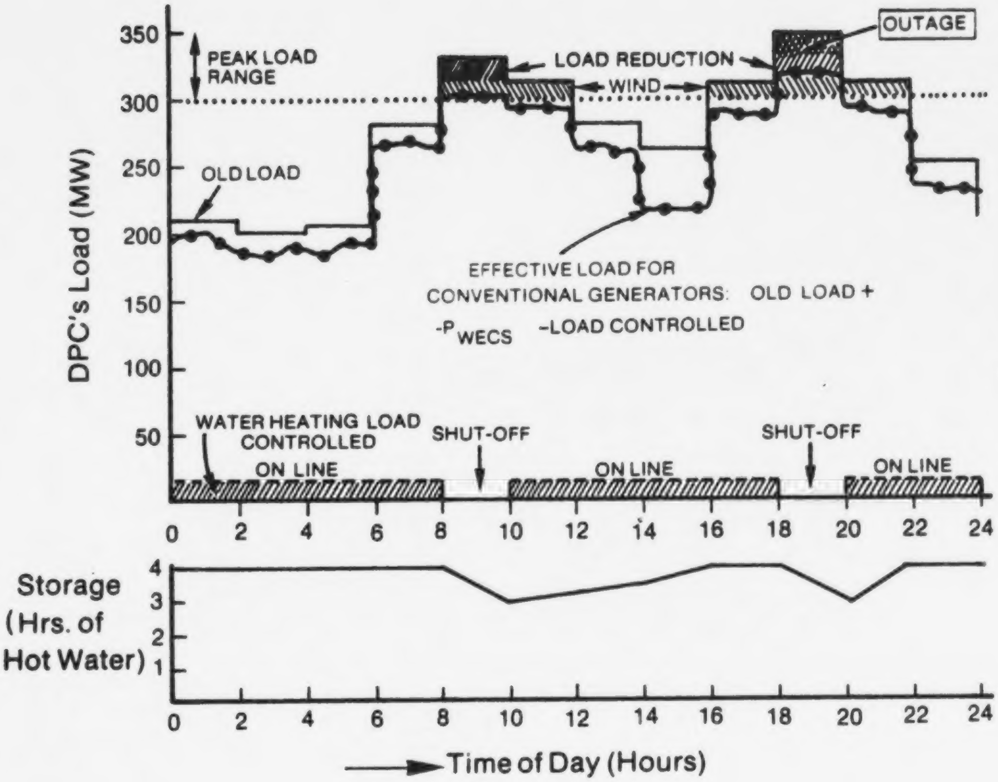

Figure 28. Schematic presentation of daily utility operations with a combined WECS plus load control system. Peak-load range from 300 to 350 MW; WECS capacity is 68 MW; controlled load is 16 MW. Hourly load curve approximates the DPC annual peak day's hourly load curve.

TABLE 26. RESULTS OF THE RELIABILITY ANALYSIS DURING 1969 TO 73 OF WECS PLUS LOAD CONTROL AS PEAK-LOAD SHAVERS WITH THREE VARIATIONS IN WECS CAPACITY AND TWO HOT WATER STORAGE CAPACITIES. 220 W/M^2 WIND_ MACHINES

	1969	1970	1971	1972	1973
(a)	2.86 kW WECS/kW of controlled load				
Annual peak (MW)	340	376	396	433	452
Peak load generating capacity (MW)	51.0	56.4	59.4	65.0	67.8
No. times peaking load met	1,177	1,000	1,099	1,062	949
WECS capacity installed (MW)	102	112.8	118.8	129.9	135.6
Size of controlled load (MW)	35.7	39.5	41.6	45.5	47.5
% time peaking load met	99	99	100	99	99
No. hours cold water: 4 h storage	1.4	1.1	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	315	249	245	281	212
WECS capacity installed (MW)	68	75.2	79.2	86.6	90.4
Size of controlled load (MW)	23.8	26.3	27.7	30.3	31.6
% time peaking load met	97	96	99	97	98
No. hours cold water: 4 h storage	6.3	8.8	0.0	0.1	3.8
8 h storage	0.15	0.0	0.0	0.0	0.0
No. times load control used	395	324	308	372	287
WECS capacity installed (MW)	51	56.4	59.4	65.0	67.8
Size of controlled load (MW)	17.8	19.7	20.8	22.7	23.7
% time peaking load met	93	90	95	92	94
No. hours cold water: 4 h storage	9.7	16.8	1.6	9.6	8.2
8 h storage	1.9	0.3	0.0	0.5	1.8
No. times load control used	458	370	371	434	348
(b)	4.29 kW WECS/kW of controlled load				
Annual peak (MW)	340	376	396	433	452
Peak load generating capacity (MW)	51.0	56.4	59.4	65.0	67.8
No. times peaking load met	1,177	1,000	1,099	1,062	949
WECS capacity installed (MW)	102	112.8	118.8	129.9	135.6
Size of controlled load (MW)	23.8	26.3	27.7	30.3	31.6
% times peaking load met	97	97	99	97	98
No. hours cold water: 4 h storage	5.1	4.7	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	315	249	245	281	212
WECS capacity installed (MW)	68	75.2	79.2	86.6	90.4
Size of controlled load (MW)	15.9	17.5	18.5	20.2	21.1
% time peaking load met	93	90	95	92	94
No. hours cold water: 4 h storage	9.3	14.8	0.95	4.5	6.0
8 h storage	1.7	0.0	0.0	0.0	0.24
No. times load control used	395	324	308	372	287
WECS capacity installed (MW)	51.0	56.4	59.4	65.0	67.8
Size of controlled load (MW)	11.9	13.2	13.9	15.2	15.8
% time peaking load met	86	83	90	85	88
No. hours cold water: 4 h storage	14.9	20.4	3.3	15	9.3
8 h storage	4.7	1.7	0.0	2.5	1.6
No. times load control used	458	370	371	434	348

TABLE 27. RESULTS OF THE RELIABILITY ANALYSIS DURING 1969 TO 73 OF WECS PLUS LOAD CONTROL AS PEAK-LOAD SHAVERS WITH THREE VARIATIONS IN WECS CAPACITY AND TWO HOT WATER STORAGE CAPACITIES. 90 W/M^2 WIND_ MACHINES

	1969	1970	1971	1972	1973
(a)	2.86 kW WECS/kW of controlled load				
Annual peak (MW)	340	376	396	433	452
Peak load generating capacity (MW)	51.0	56.4	59.4	65	67.8
No. times peaking load met	1,177	1,000	1,099	1,062	949
WECS capacity installed (MW)	102	112.8	118.8	129.9	135.6
Size of controlled load (MW)	35.7	39.5	41.6	45.5	47.5
% time peaking load met	100	100	100	100	100
No. hours cold water: 4 h storage	0.0	0.0	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	166	142	101	128	85
WECS capacity installed (MW)	68	75.2	79.2	86.6	90.4
Size of controlled load (MW)	23.8	26.3	27.7	30.3	31.6
% time peaking load met	99	98	100	98	99
No. hours cold water: 4 h storage	2.0	0.0	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	225	183	141	180	130
WECS capacity installed (MW)	51	56.4	59.4	65	67.8
Size of controlled load (MW)	17.8	19.7	20.8	22.7	23.7
% time peaking load met	96	95	98	96	97
No. hours cold water: 4 h storage	4.2	1.9	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	264	220	187	240	180
(b)	4.29 kW WECS/kW of controlled load				
Annual peak (MW)	340	376	396	433	452
Peak load generating capacity (MW)	51.0	56.4	59.4	65	67.8
No. times peaking load met	1,177	1,000	1,099	1,062	949
WECS capacity installed (MW)	102	112.8	118.8	129.9	135.6
Size of controlled load (MW)	23.8	26.3	27.7	30.3	31.6
% time peaking load met	99	98	100	99	99
No. hours cold water: 4 h storage	1.0	0.0	0.0	0.0	0.0
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	166	142	101	128	85
WECS capacity installed (MW)	68	75.2	79.2	86.6	90.4
Size of controlled load (MW)	15.9	17.5	18.5	20.2	21.1
% time peaking load met	96	96	98	97	97
No. hours cold water: 4 h storage	4.2	0.0	0.0	0.0	0.1
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	225	183	141	180	130
WECS capacity installed (MW)	51	56.4	59.4	65.0	67.8
Size of controlled load (MW)	11.9	13.2	13.9	15.2	15.8
% time peaking load met	92	90	90	93	95
No. hours cold water: 4 h storage	6.4	4.1	0.7	0.0	0.3
8 h storage	0.0	0.0	0.0	0.0	0.0
No. times load control used	264	220	187	240	180

2 times the annual peak-load capacity; i.e., in 1969, 51, 68, and 102 MW, respectively. An increase in WECS capacity results in a higher reliability to meet the peak load.

The next component of this analysis is the hour-by-hour evaluation of the DPC load, WECS power output, the controlled load, and the available hot water in storage. Figure 28 displays a schematic daily load curve and the level to which the controlled hot water heaters with a 4-hour capacity are filled. It was assumed that a peak load for a day in 1969 was the top 50 MW (close to annual peak day), WECS capacity was 68 MW, and a controlled load was 15.9 MW (Table 26b). The model analyzes the hourly load on a daily basis as follows (Figure 28):

(1) 0.00 to 8.00 hours: No peak load; WECS as fuel saver only; load control technology not in use; storage kept full.

(2) 8.00 to 10.00 hours: Peak load; WECS power output plus load controlled just sufficient to meet load; storage reduced by hour of average hot water use.

(3) 10.00 to 12.00 hours: Peak load; WECS power output exceeds the peak load; load control not needed; conventional generators meet current average hot water needs; WECS excess energy is used to partially fill storage systems. It is recognized that electricity generated by different generators is of one kind. However, the model assumes that the conventional generators are never used to refill the storage systems to avoid problems of creating new peak loads during payback periods (Electrical World 1975). Occasionally, WECS power output alone is not sufficient to keep the storage filled, which is reported as the number of hours with cold water

(4) 12.00 to 16.00 hours: No peak load; WECS as fuel saver only; load control not in use; storage completely filled by WECS only.

(5) 16.00 to 18.00 hours: Same as 10.00 to 12.00 hours.

(6) 18.00 to 20.00 hours: Peak load; WECS power output plus load controlled are not sufficient to meet peak load, which is reported as 2 hours of outage; storage is reduced.

(7) 20.00 to 22.00 hours. Same as 10.00 to 12.00 hours.

(8) 22.00 to 24.00 hours. Same as 0.00 to 8.00 hours.

This procedure is performed for all days during the 5 yr from 1969-73.

The flow chart in Figure 27 displays three types of results of the hour-by-hour analysis. The percentage of time that the WECS plus controlled load cannot meet the peak load designed is a measure of reliability. These results are calculated on a monthly and annual basis. A FOR of wind machines is not included in the analysis. Melton (1977) suggests a 3% FOR/wind machine due to mechanical failure and scheduled maintenance. He states "because a WECS will be typically comprised of a large number of identical wind machines, a statistically acceptable method for accounting for this component of outage is to simply derate the machines by the amount of expected non-wind outage." Since maintenance can be scheduled during nonpeak hours and months when wind availability generally exceeds the monthly peakload range, this FOR of 3% can be reduced and becomes negligible in relation to other inaccuracies in this analysis. A comparison with the roughly 7% FOR of conventional peak-load generators (Schoengold 1978; personal communiation), indicates whether the WECS plus load control is sufficiently reliable.

Each water heater that is controlled has a storage capacity. The analysis was performed for two storage capacities: 4 and 8 h. Thus, power supplied to these water heaters can be cut off for a total period of 4 and 8 h, respectively, before the consumer runs out of hot water, assuming an average hot water consumption (0.7 kW demand or 0.7 kWh of energy per hour).

WECS alone will refill the storage heaters. The hours that the WECS energy output is not sufficient are reported as cold water hours. It should be realized that these calculated cold water hours represent a maximum. In a practical situation, conventional generators could partially fill these storage systems during off-peak hours without creating a new peak load. It is not possible to state the maximal acceptable number of hours of cold water for the typical customer. But it appears that a long continuous period of cold water is less acceptable than when these hours are spread throughout the year.

RESULTS

Reliability, Fuel Savings, and Storage System's Capacity

The results of the simulations are displayed in Tables 26 and 27.

Table 26a encompasses the analysis of a WECS with wind machines of 220 W/m^2 rated power density, 2 kW WECS capacity/controlled water heater (2.86 kW WECS/controlled kW), and three levels of installed WECS capacity for the period 1969-73. Table 26b differs in that the capacity of WECS is increased to 4.29 kW per kW of controlled load. These tables show that the peaking load is met by the WECS plus load control 93% or more of the time when averaged over the 5 yr considered, except in the last case (bottom of Table 26b). A WECS installed capacity equal to the peaking load and a controlled load equal to 0.23 times (1/4.29) this peaking capacity meets the peak load about 86% of the time.

Thus, all but the last system have a reliability similar or better than a conventional peak-load generator. The tables also show that when the WECS capacity is equal to the peak-load range, load control equipment is used about 35 to 40% of the time that the peak-load range is reached. Thus, the WECS power output suffices 60 to 65% of the time to meet the load without help of load-control techniques. This indicates a positive correlation of peak load and wind availability. The number of hours per year without hot water is generally < 15 h/yr (0.17%) for water heaters with 4 h storage capacity and negligible with a storage capacity of 8 h. These cold hours are spread about equally over the seasons.

Tables 27a and 27b display similar results for a WECS that consists of wind machines with a rated power density of 90 W/m^2. All systems displayed have a reliability equal to or better than a conventional peak-load generator. The number of hours per year without hot water is negligible for both storage capacities.

Table 28 contains the reduction in electricity generated by the conventional generators. Fuels normally used to generate peak-load electricity are replaced almost completely by the WECS. Savings in nonpeak electricity are significant also. Note that these savings are calculated in terms of reductions in electricity to be produced by the conventional generators. A rough approximation of actual fuel savings is obtained by dividing these savings by the average efficiency of the generators (often estimated at about 30 to 40%). A more accurate model can be obtained only if the analysis makes use of a production cost model as described in Section 7.

TABLE 28. SAVINGS IN CONVENTIONALLY GENERATED ELECTRICITY BY THE ADDITION OF A WECS PLUS LOAD CONTROL. ASSUMPTIONS EQUAL THOSE OF THE THIRD CASE IN TABLES 26a AND 27a

	Reduction in conventionally generated electricity (%)				
	1969	1970	1971	1972	1973
220 W/m^2 wind machines (Table 26a)					
Peak load electricity	96	94	98	95	96
Nonpeak load electricity	9	12	11	10	11
90 W/m^2 wind machines (Table 27a)					
Peak load electricity	98	97	99	97	98
Nonpeak load electricity	14	16	16	15	16

Correlation of Wind Availability and Dairyland Power Cooperative Load

The positive correlation between the DPC load and wind availability increases the viability of WECS with and without load control. Figure 29 illustrates the positive correlation of the power output of WECS with both 90 and 220 W/m^2 wind machines and the DPC load for the year 1969. The graph is basically a power output duration curve, except that the units of the vertical axis are in percent of the load to be met. Two cases are shown in the graph, both of which are for the same array of wind machines as used before, 60-m height, annual curves, and a WECS capacity of 51 MW equal to the DPC peaking range in 1969:

(1) The two curves on the left side of the graph represent the situation when the WECS is expected to meet a constant (base-) load of 51 MW. These curves are calculated by using the array simulation model and are similar to power output duration curves. As expected, the 90 W/m^2 wind machines meet this load more often than the 220 W/m^2 machines, 18 and 8% of the time, respectively.

(2) The two curves on the right side represent the situation when the WECS is expected to meet the top 15% of monthly peak demands. This peaking load in 1969 varies from 51 MW in December to about 34 MW in May and June. The curves are obtained by employing the simulation model with the controlled load set equal to zero. The WECS meets the varying load about 80% of the time for the 90 W/m^2 wind machines and 60% of the time for the 220 W/m^2 wind machines. Monthly values for the 90 W/m^2 wind machines range from 61% in July to 88% in January and for the 220 W/m^2 wind machines 43% in September and 81% in January.

Figure 29 shows that the DPC load and a WECS power output correlate to a significant degree. Seasonal correlation is largely due to the important heating load on the DPC system, whereas the diurnal variation in WECS power output is particularly important during the summer months (Figure 13).

Figure 29 also illustrates the effects of load control on the percentage of time the peaking demand is met. The curves on the right side move up vertically with the amount of controlled load, thereby increasing the reliability. For example, the two systems presented at the bottom of Tables 26a and 26b have a controlled load equal to 35 and 24%, respectively, of the 51 MW peaking load range. Since load control techniques basically have a zero FOR, values on the horizontal axis in Figure 29 presently associated with a power output of 65 and 76%, respectively, of the load to be met will become the improved reliability percentages. These values are 93 and 86% of the time, which equal the values in Tables 26a and 26b. The same procedure can be shown for the 90 W/m^2 wind machines.

It should be emphasized that the analysis is based on historical synchronous load and wind speed data. The results are valid for the DPC,

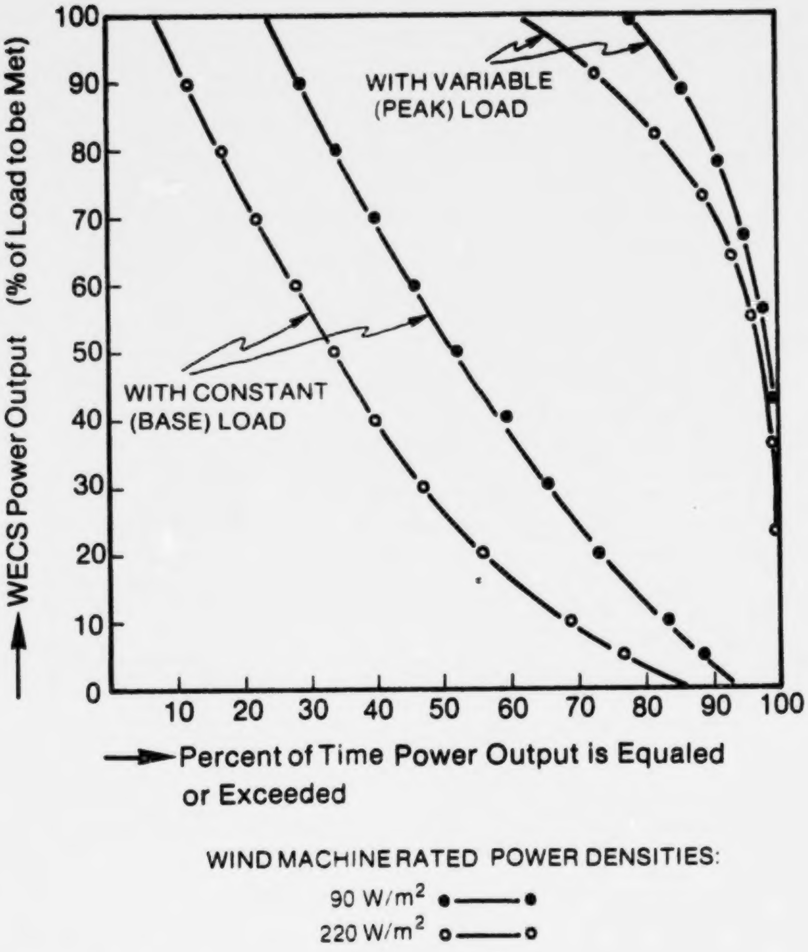

Figure 29. WECS annual power output duration curves in percent of 1969 load to be met for an array of 60-m height wind machines in Rochester, Mason City, and Waterloo.

although analyses of other rural-based utilities in the northern sections of the United States may show similar results.

Finally, Figure 30 shows the monthly variation of several energy sources and the DPC load. Wind availability positively correlates not only with the DPC load, but also with Wisconsin natural gas use and nontransportation petroleum deliveries. This indicates that WECS may have a good potential to replace these fuels in many cases.

An Economic Analysis

Economic considerations of the combined WECS and load control system include the incremental cost of controlled hot water heaters, WECS costs, electricity production cost savings, and capital cost savings of the conventional generating capacity replaced. If wind machines are installed close to the load, transmission costs and losses decrease. These additional savings are not included here.

Two of the 12 WECS plus load control systems displayed in Tables 26 and 27 have an average reliability equal to a conventional peak-load generator with an FOR = 7%: the second system in Table 26b (68 MW WECS plus 16 MW controlled load in 1969) and the last system in Table 27b (51 MW WECS plus 12 MW controlled load in 1969).

Molander and Heitner (1976) and Asbury et al. (1976) evaluated a variety of thermal energy storage systems. These studies estimated the incremental equipment and installation cost of ripple-controlled hot water storage systems with 4- and 8-h storage capacity at $110 and $140/installation, respectively. These incremental costs include the increased tank capacity (estimated at 2 and 12.5 gal for the 4- and 8-h storage capacity), ripple control receiver and its share of the transmitter cost, and installation. The results in Tables 26b and 27b of the two systems indicate that a 4-h storage capacity will be sufficient for most customers of the DPC. Since it is assumed for both systems that 3 kW of WECS are installed per water heater, the cost of load control equals $37/kW WECS ($110 ÷ 3).

If one assumes that the WECS plus load control replaces a peak-load generator such as a combustion turbine, capital cost savings are about $180/kW/ combustion turbine replaced (Schoengold 1978: personal communication). In the first of the two cases considered (Table 26b, 68 MW of WECS plus 16 MW of controlled load replace the peak load range of 51 MW (1969)). Thus, capital cost savings per kW WECS are:

$$\frac{51}{68} \times \$180 = \$135$$

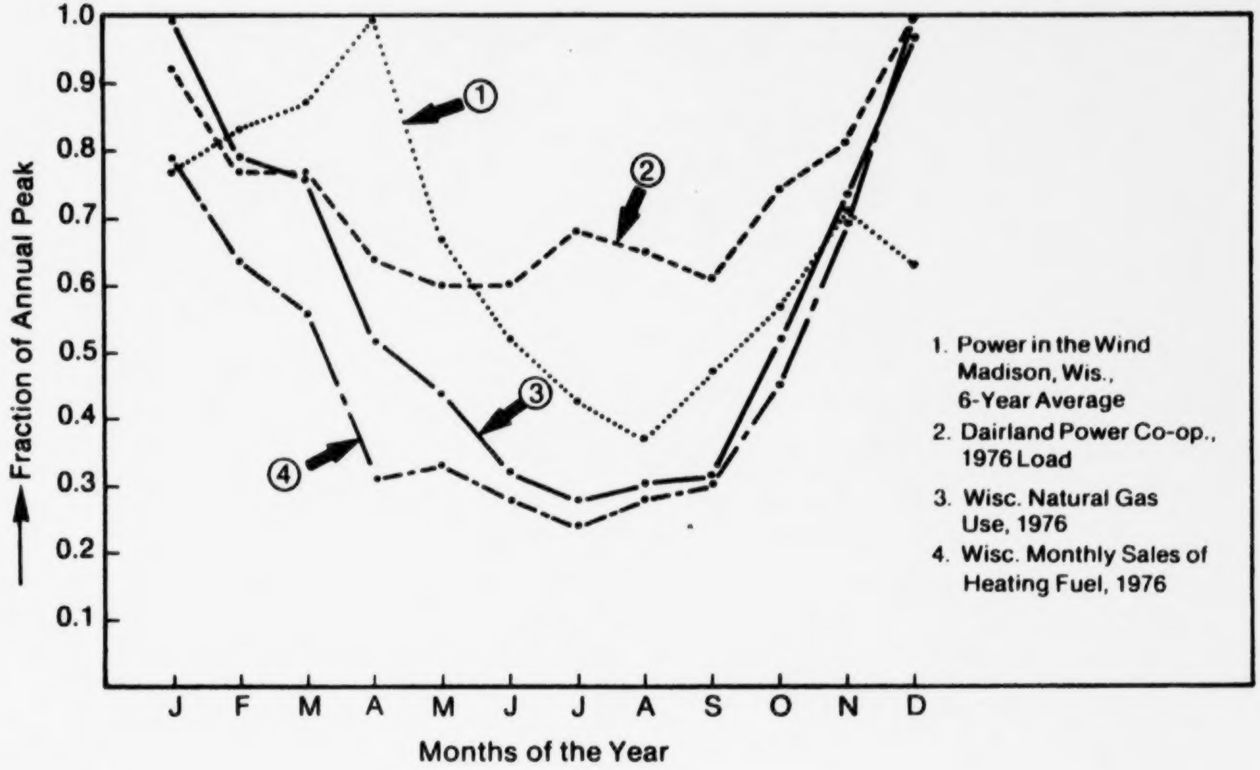

Figure 30. Monthly variation in heating fuels for the Dairyland Power Cooperative load and the power in the wind (Aigner et al. 1977; Western Wisconsin Utilities 1978).

Net benefits equal these capital cost savings minus the cost of the controlled storage systems:

$135 - $37 = $98/kW WECS

This represents an increase of about 10 to 13% in the break-even cost of WECS based on production cost savings (Figure 23). It is assumed here that the analyses of both time periods, 1969-73 and 1985-91, are similar in that (1) both are based on hour-by-hour simulation with data of approximately the same time period, and (2) the WECS saves in both cases by reducing the energy production of the most expensive generators first (except during the refilling of storage systems by the WECS during nonpeak hours).

The second system considered consists of 51 MW of WECS capacity (90 W/m^2 wind machines) and 12 MW of load controlled. This combination replaces 51 MW of peak-load generators, which results in capital cost savings of $180/kW WECS. Net benefits per kW of WECS are about $140, or about a 10 to 14% increase in break-even cost for the 90 W/m^2 wind machines (Figure 24). The same considerations and assumptions as for the previous case are pertinent here.

The analysis of WECS plus load control replacing a peak-load generator indicates that the WECS break-even cost of both the 220 and 90 W/m^2 wind machines (Figures 23 and 24) increases about 10 to 14%. The reliability of such a system is comparable to the one of combustion turbines.

Another way of evaluating the WECS plus load control is to assume that the existing generating units can be operated at higher capacity factors when the WECS plus load control is installed to meet the peak-load range. A planned base-load generator can then be replaced/delayed. Capital cost savings per kW WECS for the two cases considered are, $750 and $1,000, respectively, with an estimated $1,000/kW nuclear base-load unit. Subtracting the cost of load control results in net benefits of about $700 and $950/kW WECS. These are capital cost considerations only. Contrary to the analysis of a peak-load generator replacement, production costs will change significantly when a base-load generator is replaced or delayed by the WECS plus load control. Fuel savings by the WECS plus load control are (partially) offset by the increased consumption of coal that is presumably more expensive than nuclear fuel.

A detailed analysis, as reported in Section 7, is required to evaluate the change in production costs. Although the break-even cost of a WECS plus load control cannot be determined without a detailed analysis, capital cost savings are equal to or slightly less than cost estimates of wind machines at moderate production levels. Therefore, it appears that the installation of a WECS plus load control may be an economically attractive alternative to base-load units with high capital costs. Further analysis is needed to evaluate this concept.

Implications for DPC's Proposed Expansion Plan

Section 7 evaluates WECS added to the DPC proposed expansion plan without changing the mix of the conventional generators proposed. However, as shown in Figure 18, DPC's annual load duration curve significantly changes when WECS is added. This may warrant a change in the mix of conventional generators.

A different way of evaluating a change in the generating mix is to add a WECS plus load control. For example, assume that 200 MW of WECS and 47 MW of water heating controlled load can be installed in 1985 on the DPC system. The 200 MW of WECS is about 22% of the 1985 predicted load of the DPC With a WECS to controlled load ration of 4.29, results presented in Tables 26b and 27b indicate that the top 15% of the load (140 MW in 1985) can be reliably met by the WECS and load control. The expansion plan of DPC calls for a base-load generating addition of 1985, which is proposed to be the 143 MW share of Tyrone 1. However, DPC can employ Alma 6 (350 MW) as a base-load generator, roughly doubling the capacity factor of 0.35 reported in Figure 20 (with 200 MW WECS). Other generators may serve as intermediate units. Thus the 200 MW of WECS plus 47 MW of water heating load will effectively eliminate the need for the 143 MW of Tyrone 1. Annual additions to the WECS and controlled load are possible and offer an additional flexibility that is valuable in times of uncertain growth in demand. Note that generators other than Tyrone can be replaced partially by a WECS plus load control.

It is realized that this analysis is preliminary in nature, but it points out that a detailed analysis of WECS plus load control is warranted. Both the production costs and reliability models (powerpoolwide) of DPC should be employed. The manufacturing of 200 MW of wind machines by 1985 appears possible and may be bought on "turnkey" contracts. The size of the water heating controlled load of 47 MW is only slightly higher than estimated by the DPC (see also Table 25). A stronger incentive program will most likely increase the number of controlled water heaters. Other thermal storage systems could be included.

Both small and large wind machines were discussed in Section 8. Whereas the large machines are presumably operated by the utility, smaller ones may be owned by a farmer, commercial entrepreneur, or a homeowner. It can be envisioned, e.g., that a farmer owns a wind machine (interconnected with DPC grid) and a directly controlled milk cooling and hot water system. Such a system can shave the DPC peak demand. Other combinations of WECS plus controlled space and water heating ("wind furnace," McGowan et al. 1975) may prove to be even better. The pertinent question is what kind of rate structure will be equitable for all DPC customers. Although each WECS-DPC interface will present a unique situation, some generalization, at least per member cooperative, can most likely be made. Feldman and Anderson (1976) suggest a detailed marginal cost analysis of the impact of solar space conditioning on each electric utility. Such a method can also be employed for WECS.

Socioenvironmental Considerations

The analysis in this chapter points towards the possibility of replacing conventional generating capacity by WECS plus load control. Based on these preliminary results, it appears that such a system may eliminate the need for the DPC share of Tyrone 1 or other base-load generators. Thus, advantages of not building coal-fired power plants or taking the nuclear road, as mentioned by many authors (e.g., Lovins 1976; NCC 1976; Caputo 1977; Flowers 1978), should be taken into account when evaluating the WECS plus load control.

Concluding Remarks

The discussion presented in this chapter indicates that the growing low temperature heating load on the DPC system requires the installation of an active load control system. A combination of a WECS and controlled water water heating load may meet the peak load with the same reliability as conventional peak-load generators. Although a detailed production cost analysis of such a system is necessary, preliminary results indicate that the WECS break-even costs are higher than those presented in Section 8. A combined WECS plus load control system may eliminate or delay the need for base-load generating capacity such as the DPC share of Tyrone 1. The assessment of synchronous load and wind power data during 1969-73 indicates a high positive correlation. The issue of electricity rates for individuals/firms that own a WECS with or without a controlled storage system requires a careful study.

Thus, based on this preliminary analysis, WECS plus load control appear to be a suitable alternative to additions of conventional capacity. Aside from the advantage of using a renewable (flow) resource, this system offers a flexibility with short lead times which is important in times of uncertainty. A detailed analysis is required to verify these preliminary findings. Furthermore, additional experience with both capital and O & M cost of wind machines, as well as wind speed observations at good windy locations are needed to make a more accurate assessment.

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APPENDIX A

MONTHLY AVERAGE WIND SPEEDS FOR 12 LOCATIONS IN WISCONSIN AND SURROUNDING STATES AT FOUR HEIGHTS

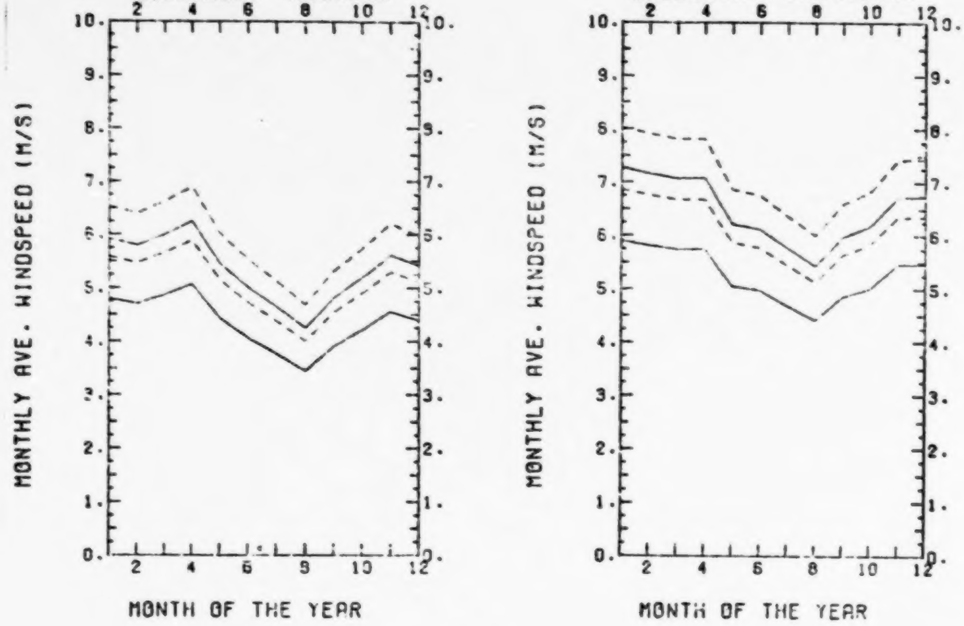
Annual average wind speed (m/sec) for 6 yr for locations in and around the state of Wisconsin. Height adjustment with simple power law exponent equal to 0.14. Wind speed observations, 1969-74, made at a height of approximately 7 m.

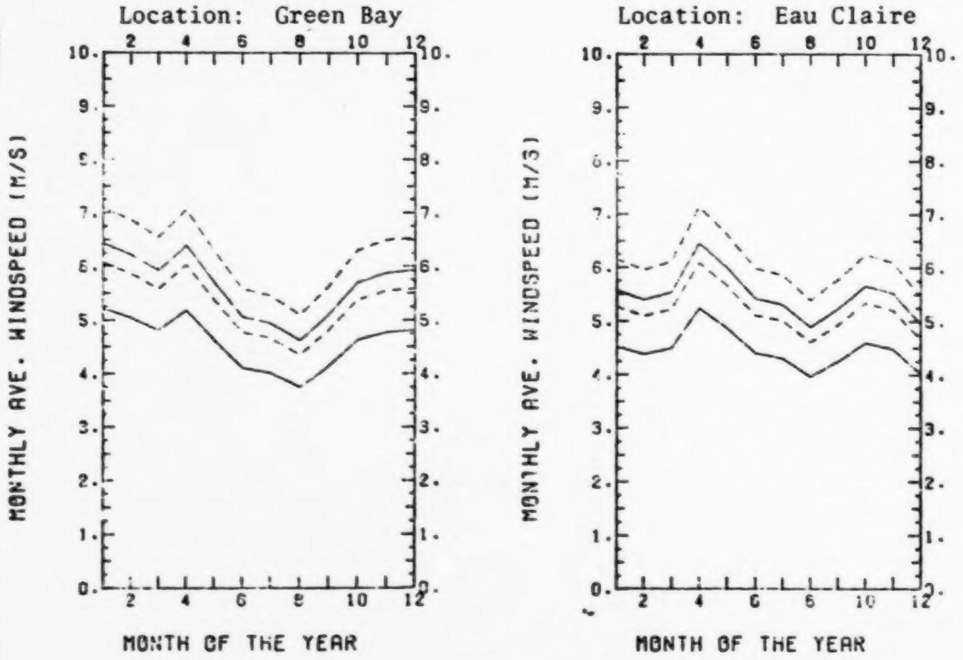
	Annual average wind speed (m/sec)			
	Height aboveground (m)			
	7	20	30	60
Madison, Wis.	4.4	5.1	5.4	5.9
Milwaukee, Wis.	5.3	6.1	6.5	7.2
Green Bay, Wis.	4.6	5.3	5.7	6.2
Eau Claire, Wis.	4.5	5.2	5.5	6.1
Duluth, Minn.	4.7	5.4	5.8	6.4
Minneapolis, Minn.	4.5	5.3	5.6	6.2
Rochester, Minn.	5.9	6.8	7.3	8.0
Mason City, Iowa	5.1	6.0	6.3	7.0
Waterloo, Iowa	5.1	6.0	6.3	7.0
Rockford, Ill.	4.6	5.4	5.7	6.3
Moline, Ill.	4.4	5.2	5.5	6.0

Data averaged over 1969 to 74. The lowest curve presents wind speeds at 7 m which is approximately the height of observation. The other wind speeds at, respectively, 20 m, 30 m, and 60 m respectively are obtained by adjusting the wind speed with the 1/7-power law.

MONTHLY AVERAGE WIND SPEED

(Four heights: 7, 20, 30, 60 meters)

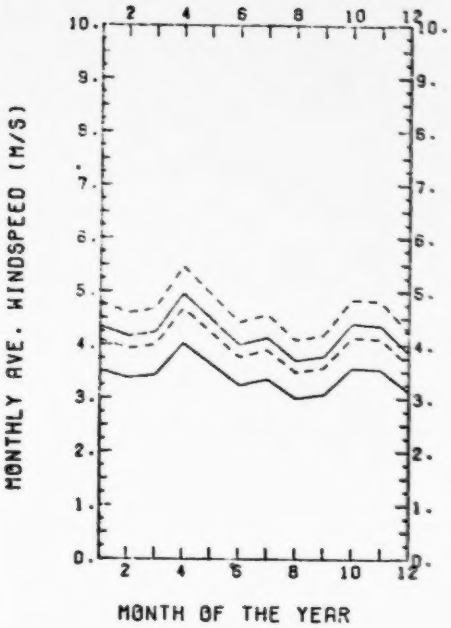




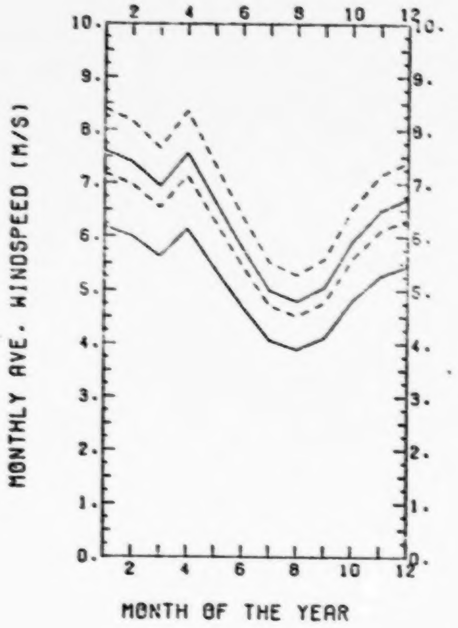
MONTHLY AVERAGE WIND SPEED

(Four heights: 7, 20, 30, 60 meters)

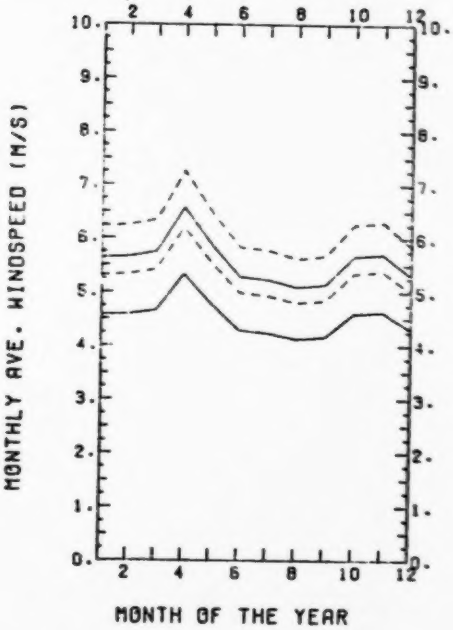
Location: La Crosse



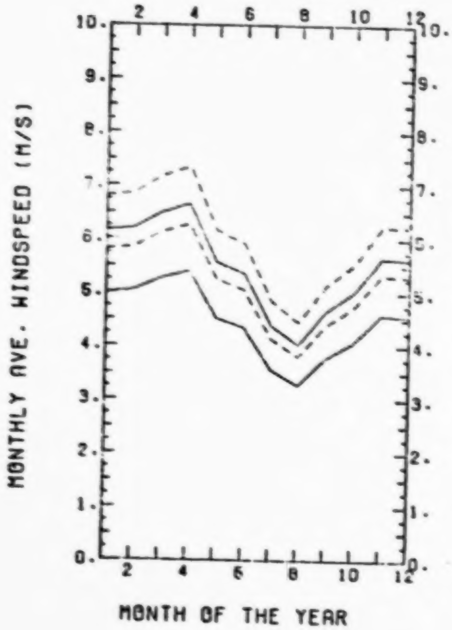
Location: Mason City



Location: Minneapolis



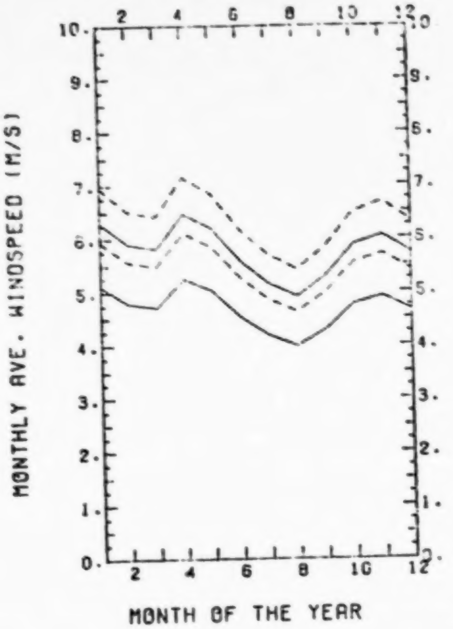
Location: Moline



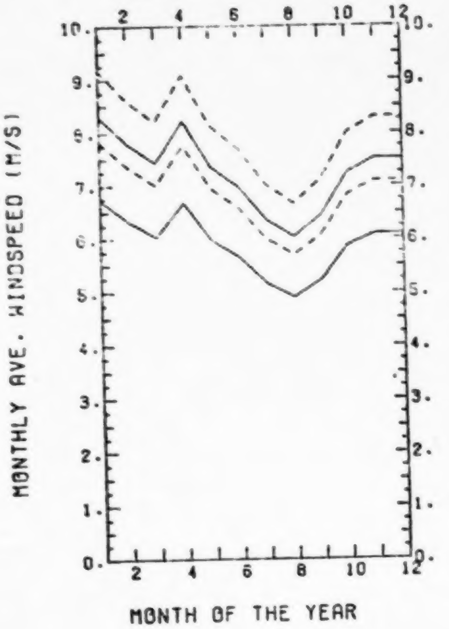
MONTHLY AVERAGE WIND SPEED

(Four heights: 7, 20, 30, 60 meters)

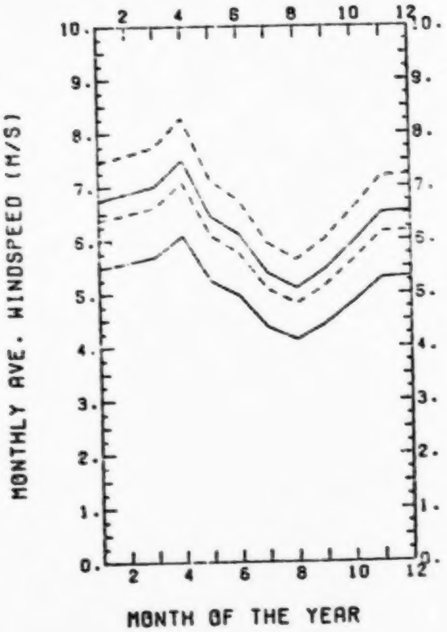
Location: Duluth



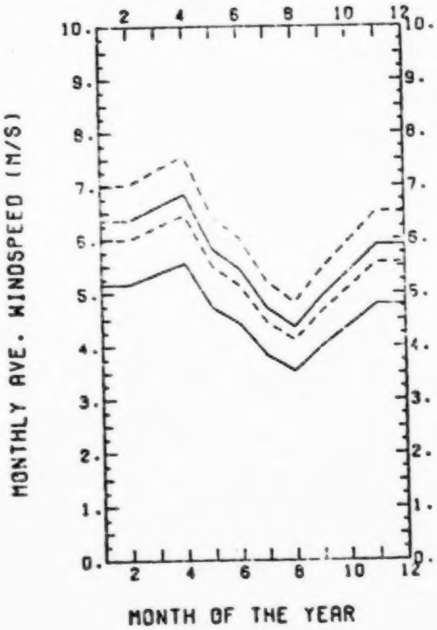
Location: Rochester



Location: Waterloo



Location: Rockford



APPENDIX B

MONTHLY AVERAGE WIND POWER DENSITY FOR 12 LOCATIONS IN WISCONSIN AND SURROUNDING STATES AT FOUR HEIGHTS

Annual average wind speed (m/sec) for 6 yr for locations in and around the state of Wisconsin. Height adjustment with simple power law exponent equal to 0.14. Wind speed observations, 1969-74, made at a height of approximately 7 m.

	Annual average wind speed (m/sec)			
	Height aboveground (m)			
	7	20	30	60
Madison, Wis.	4.4	5.1	5.4	5.9
Milwaukee, Wis.	5.3	6.1	6.5	7.2
Green Bay, Wis.	4.6	5.3	5.7	6.2
Eau Claire, Wis.	4.5	5.2	5.5	6.1
La Crosse, Wis.	3.4	4.0	4.2	4.6
Duluth, Minn.	4.7	5.4	5.8	6.4
Minneapolis, Minn.	4.5	5.3	5.6	6.2
Rochester, Minn.	5.9	6.8	7.3	8.0
Mason City, Iowa	5.1	6.0	6.3	7.0
Waterloo, Iowa	5.1	6.0	6.3	7.0
Rockford, Ill.	4.6	5.4	5.7	6.3
Moline, Ill.	4.4	5.2	5.5	6.0

Data averaged over 1969-74. The lowest curve presents wind speeds at 7 m which is approximately the height of observation. The other wind speeds at 20, 30, and 60 m, respectively, are obtained by adjusting the wind speed with the 1/7-power law.

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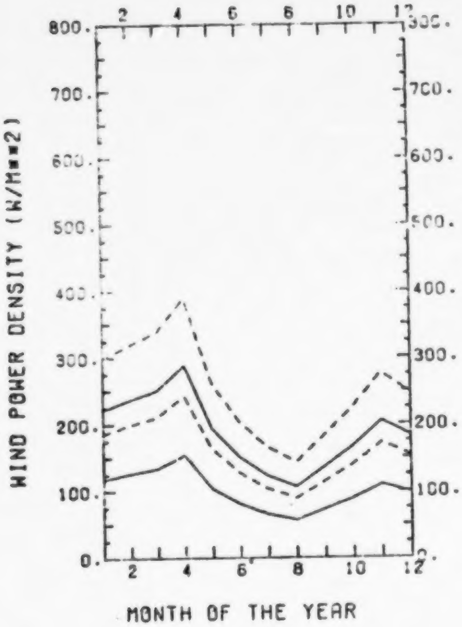
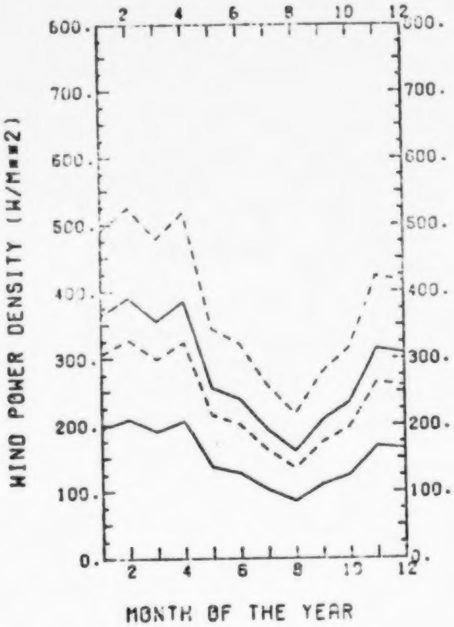
MONTHLY AVERAGE WIND POWER DENSITY

(Four heights: 7, 20, 30, 60 meters)

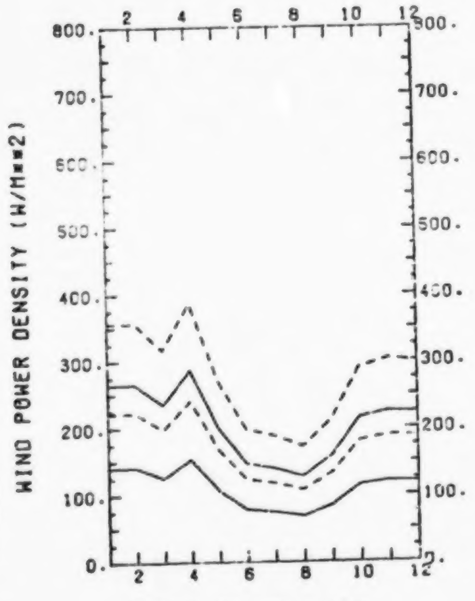
Location: Madison



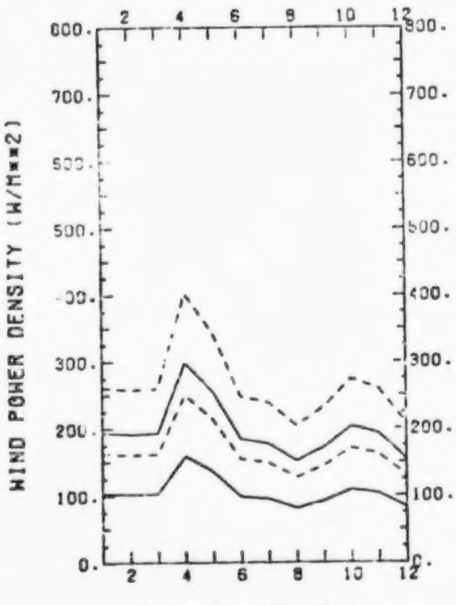
Location: Milwaukee



Location: Green Bay

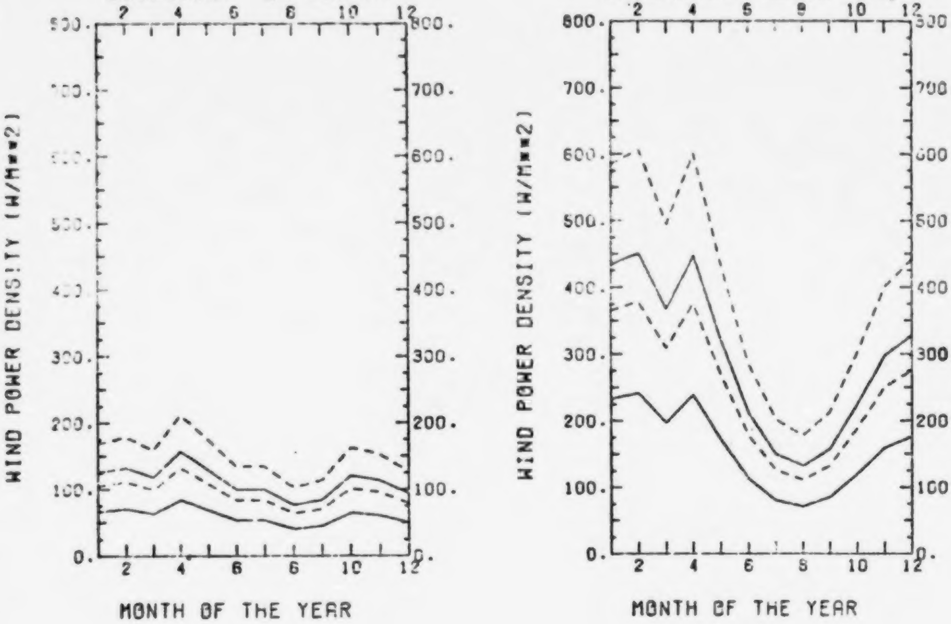


Location: Eau Claire

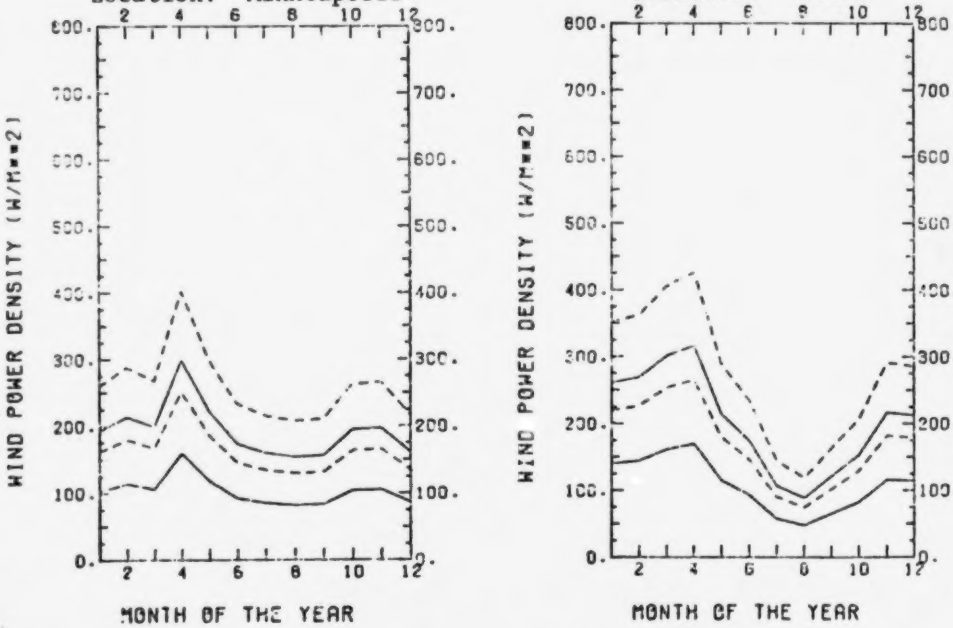


MONTHLY AVERAGE WIND POWER DENSITY

(Four heights: 7, 20, 30, 60 meters)


Location: La Crosse

Location: Mason City

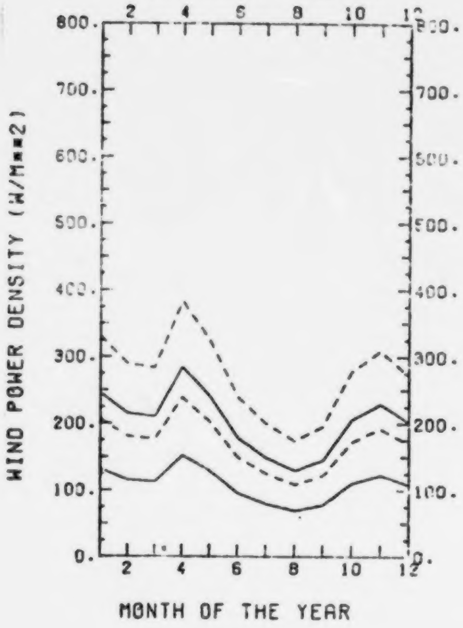

Location: Minneapolis

Location: Moline

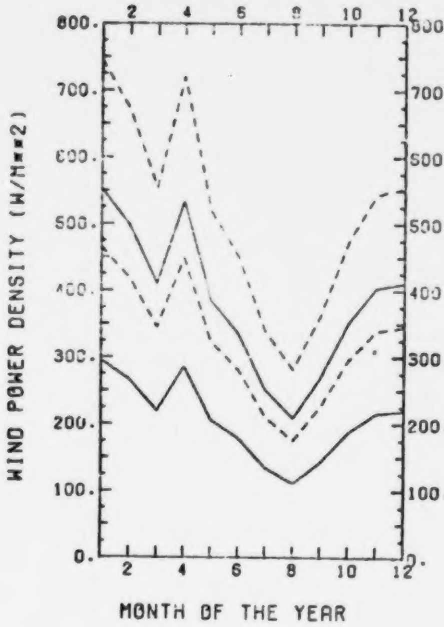
MONTHLY AVERAGE WIND POWER DENSITY

(Four heights: 7, 20, 30, 60 meters)

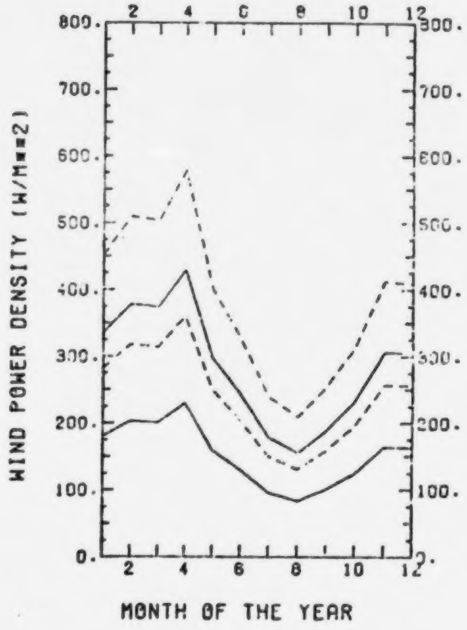
Location: Duluth



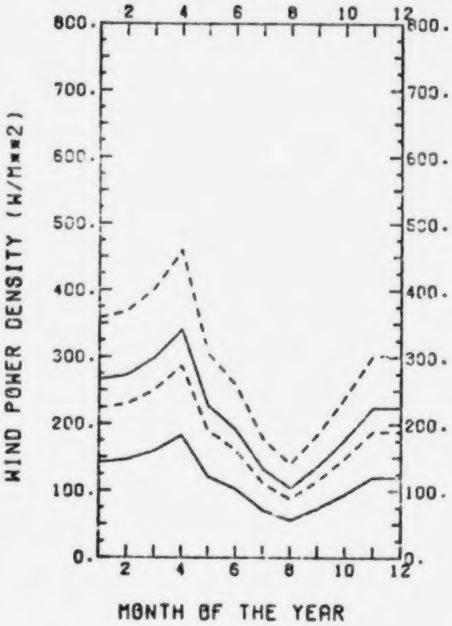
Location: Rochester



Location: Waterloo



Location: Rockford



APPENDIX C

MONTHLY AVERAGE CAPACITY FACTORS FOR THREE WIND MACHINES WITH RATED POWER DENSITIES OF 90, 220, AND 305 W/M^2 FOR 12 LOCATIONS IN WISCONSIN AND SURROUNDING STATES AT THREE HEIGHTS

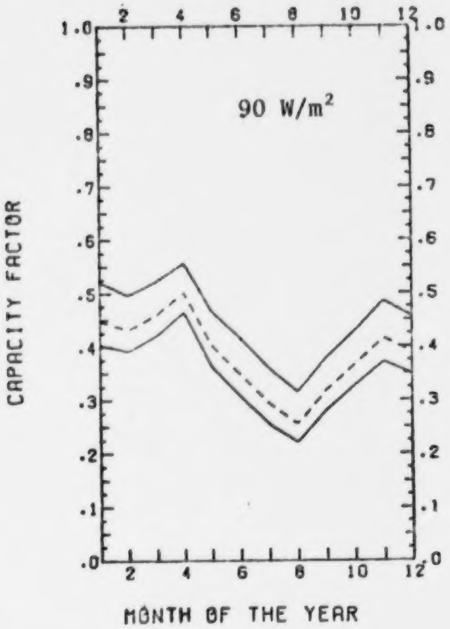
Annual average wind speed (m/sec) for 6 yr for locations in and around the state of Wisconsin. Height adjustment with simple power law exponent equal to 0.14. Wind speed observations, 1969-74, made at a height of approximately 7 m.

	Annual average wind speed (m/sec)			
	Height aboveground (m)			
	7	20	30	60
Madison, Wis.	4.4	5.1	5.4	5.9
Milwaukee, Wis.	5.3	6.1	6.5	7.2
Green Bay, Wis.	4.6	5.3	5.7	6.2
Eau Claire, Wis.	4.5	5.2	5.5	6.1
La Crosse, Wis.	3.4	4.0	4.2	4.6
Duluth, Minn.	4.7	5.4	5.8	6.4
Minneapolis, Minn.	4.5	5.3	5.6	6.2
Rochester, Minn.	5.9	6.8	7.3	8.0
Mason City, Iowa	5.1	6.0	6.3	7.0
Waterloo, Iowa	5.1	6.0	6.3	7.0
Rockford, Ill.	4.6	5.4	5.7	6.3
Moline, Ill.	4.4	5.2	5.5	6.0

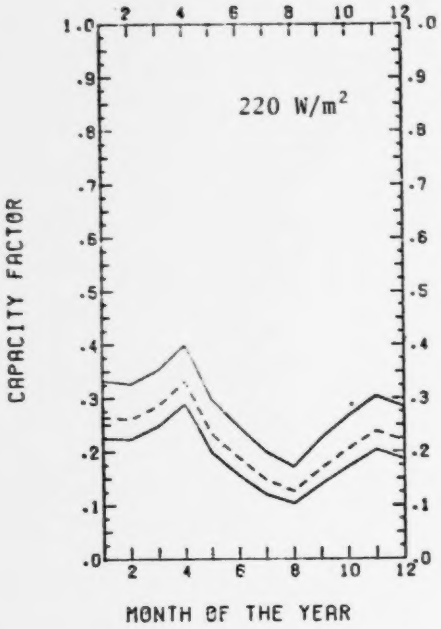
Data averaged over 1969-74. One-seventh-power law is used for height adjustments of wind speeds. Capacity factors are given at three heights: 20 (lowest curve), 30, and 60 m (highest curve).

MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

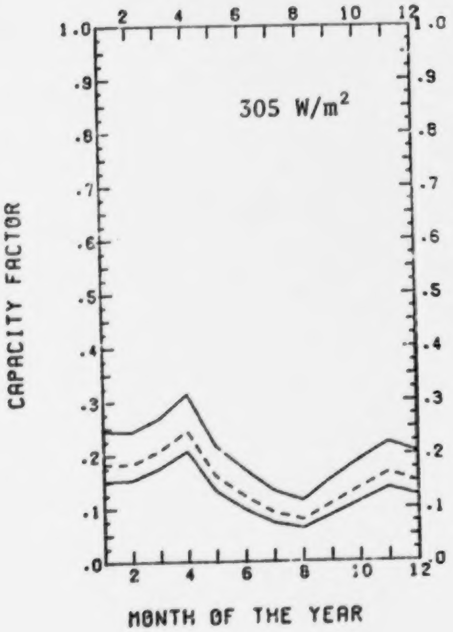
Location: Madison



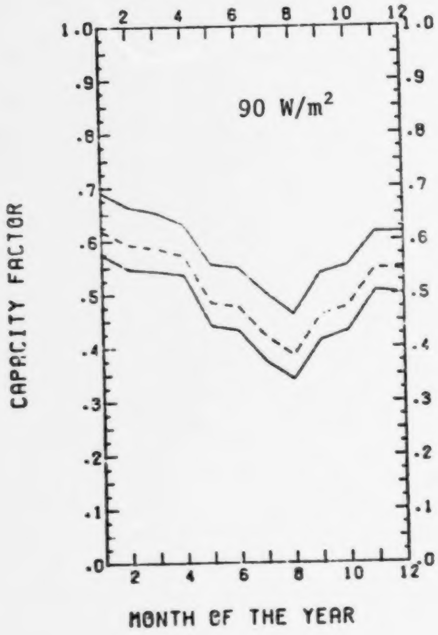
Location: Madison



Location: Madison

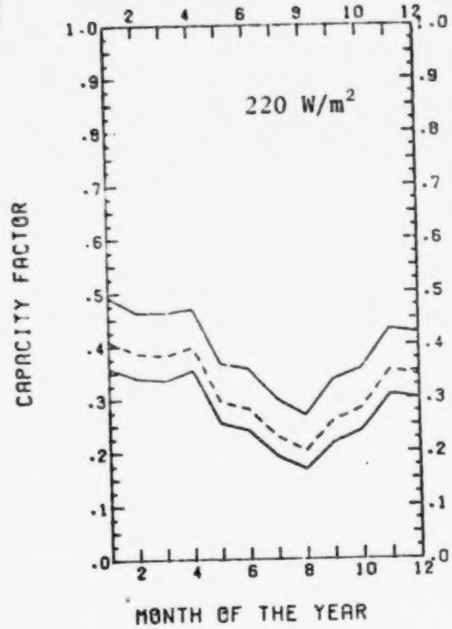


Location: Milwaukee

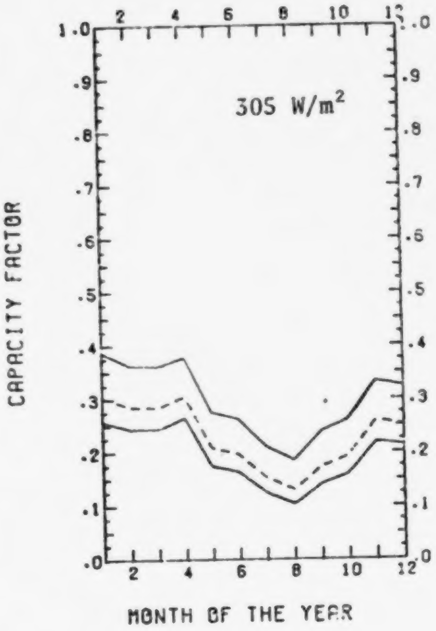


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

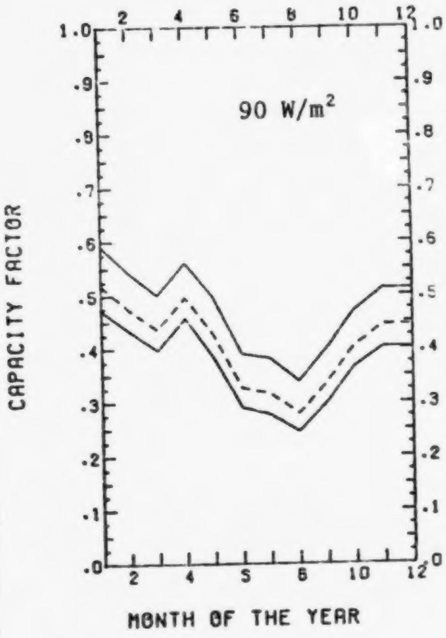
Location: Milwaukee



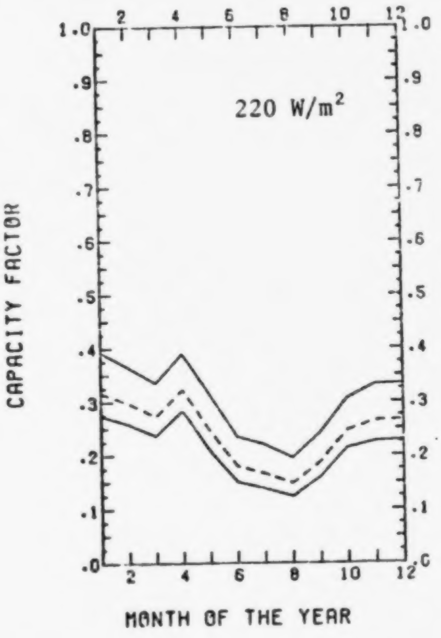
Location: Milwaukee



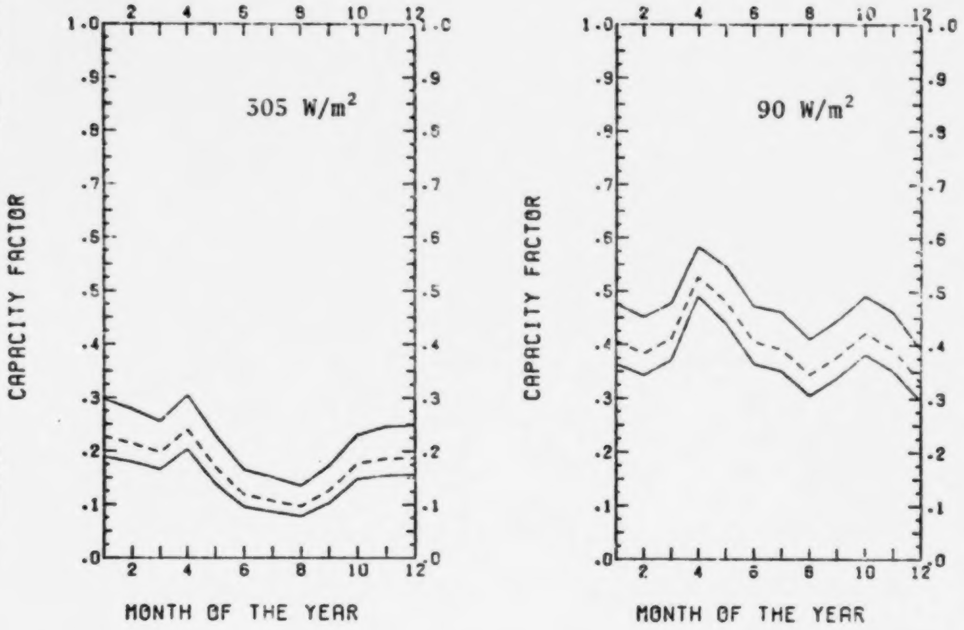
Location: Green Bay



Location: Green Bay

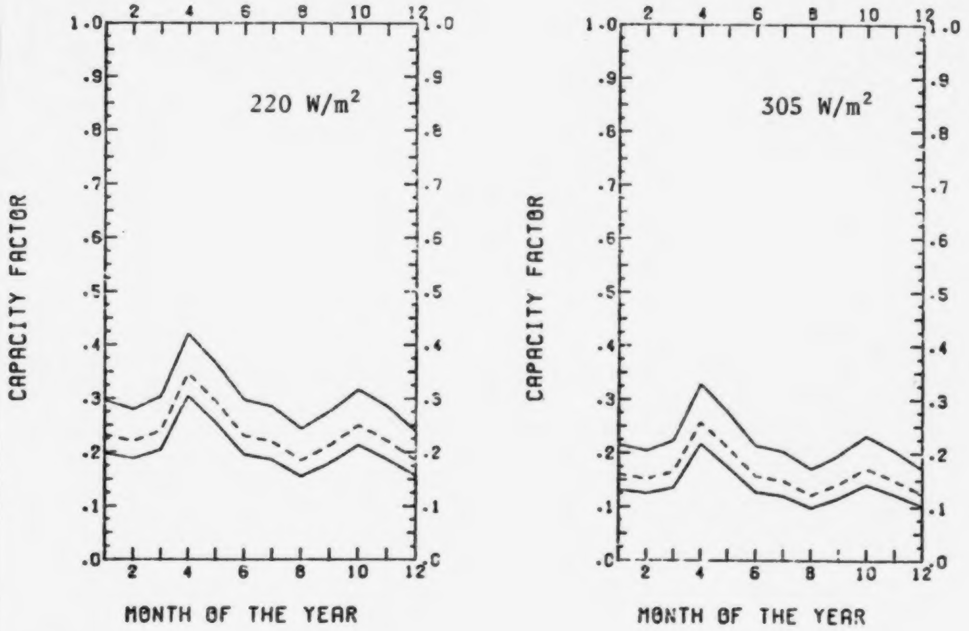


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS



Location: Green Bay

Location: Eau Claire

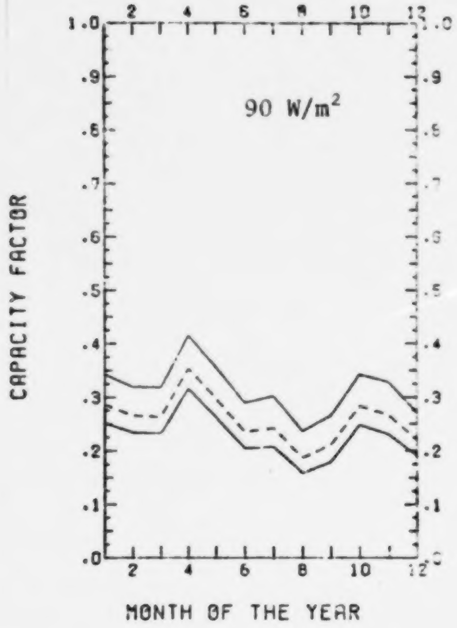


Location: Eau Claire

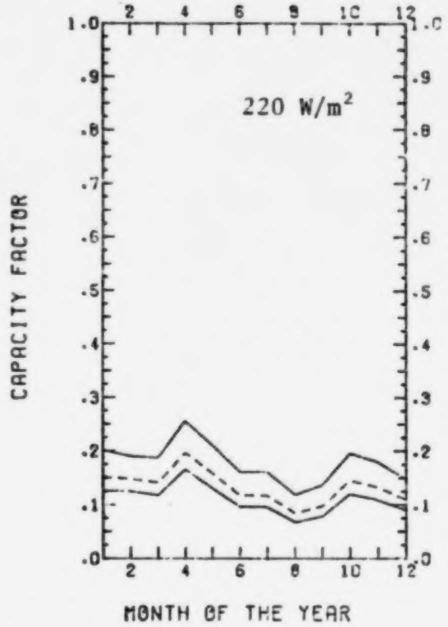
Location: Eau Claire

MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

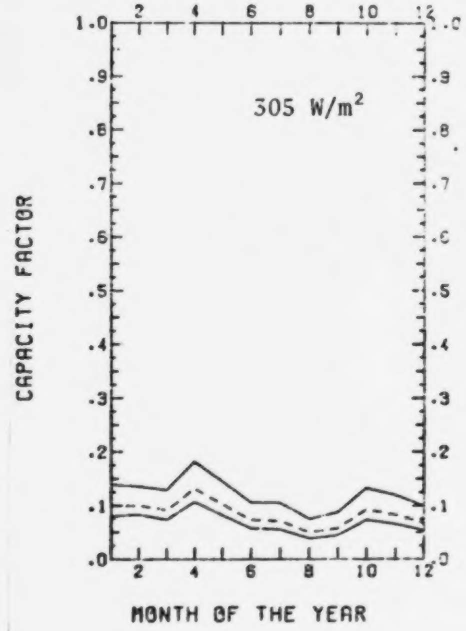
Location: La Crosse



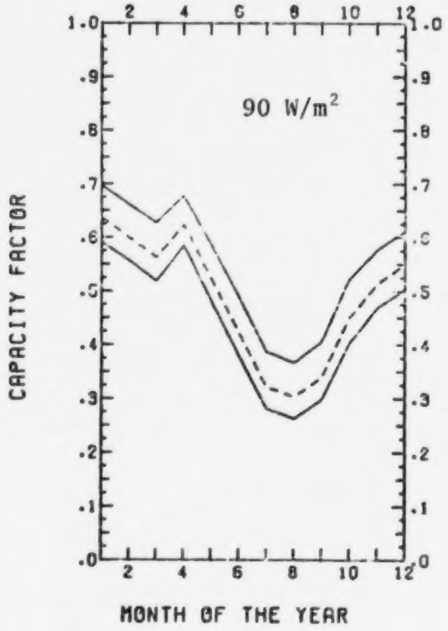
Location: La Crosse



Location: La Crosse

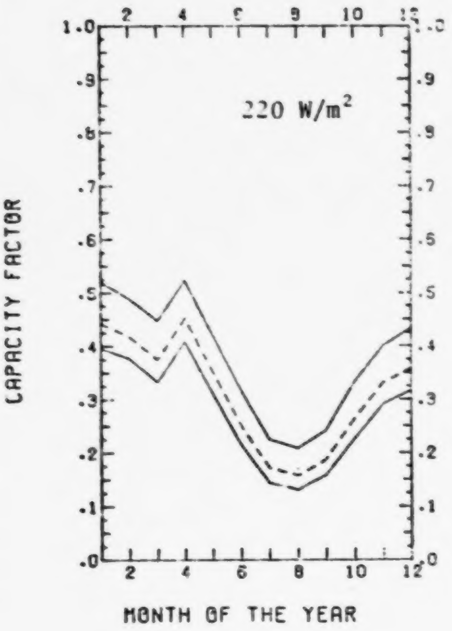


Location: Mason City

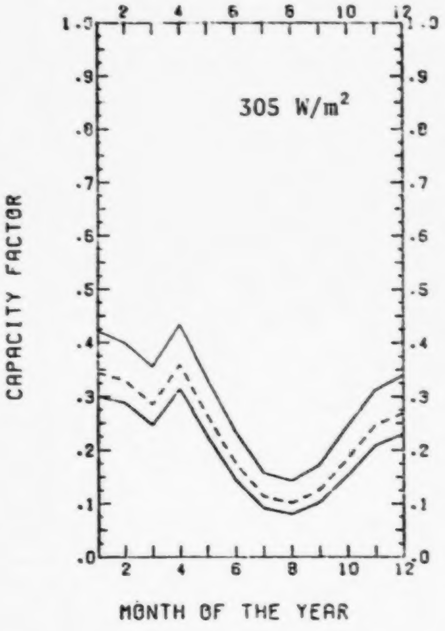


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

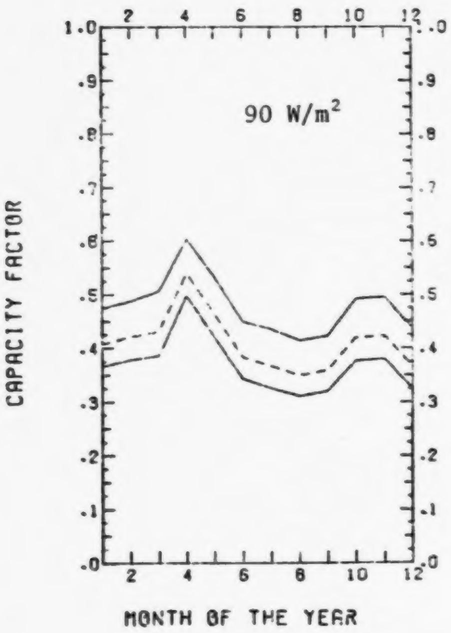
Location: Mason City



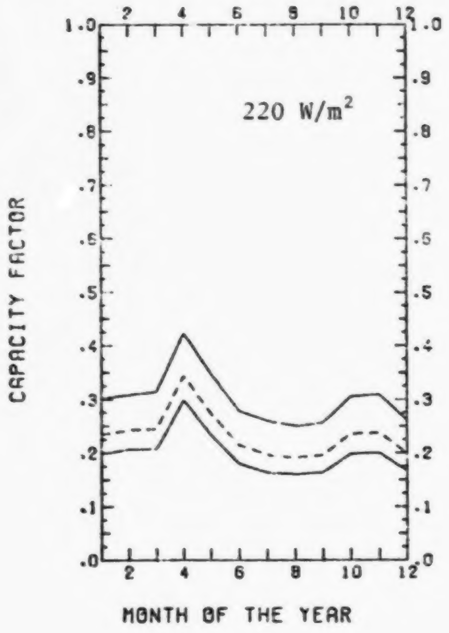
Location: Mason City



Location: Minneapolis

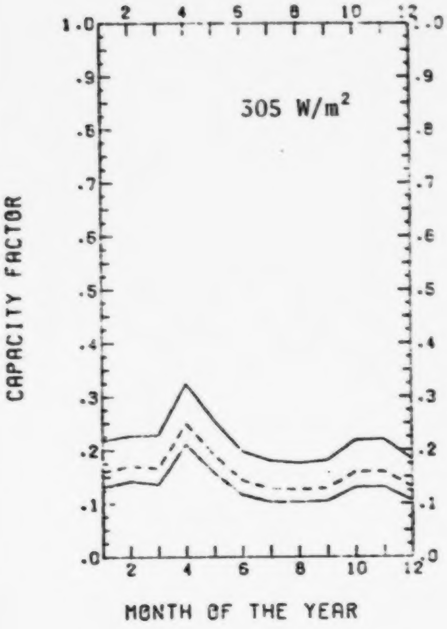


Location: Minneapolis

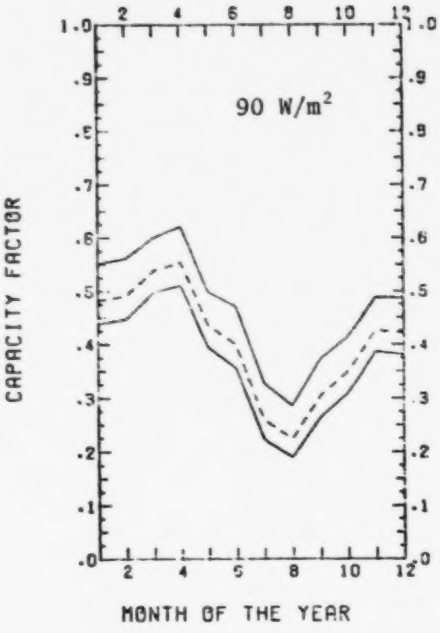


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

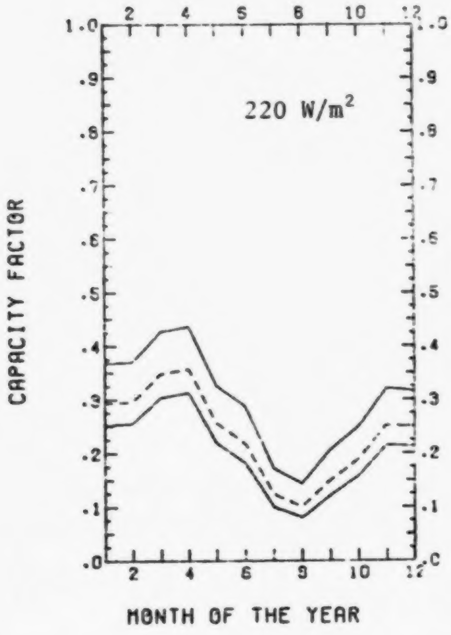
Location: Minneapolis



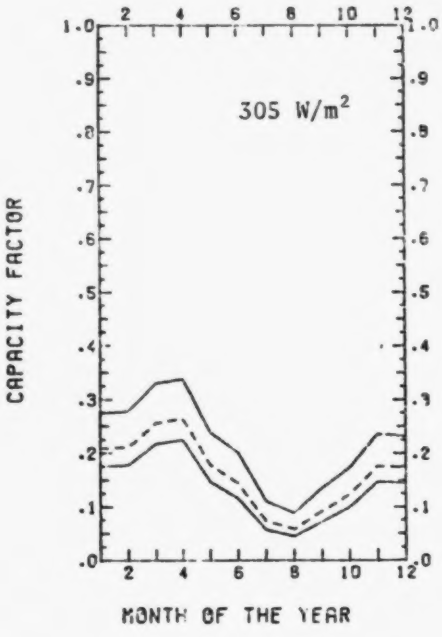
Location: Moline



Location: Moline

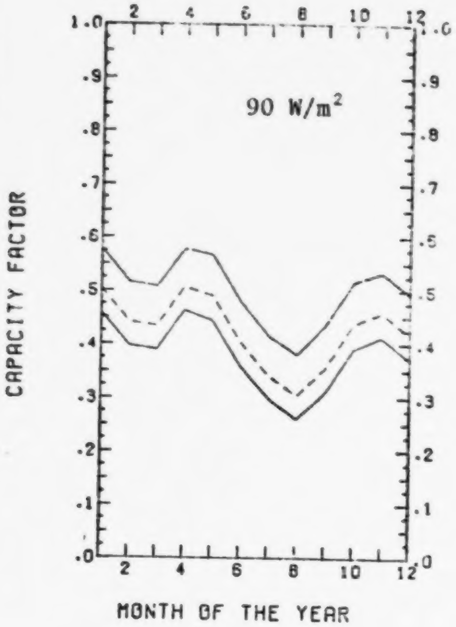


Location: Moline

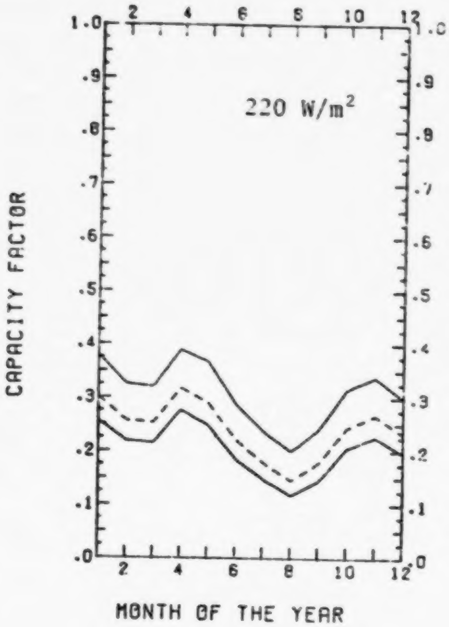


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

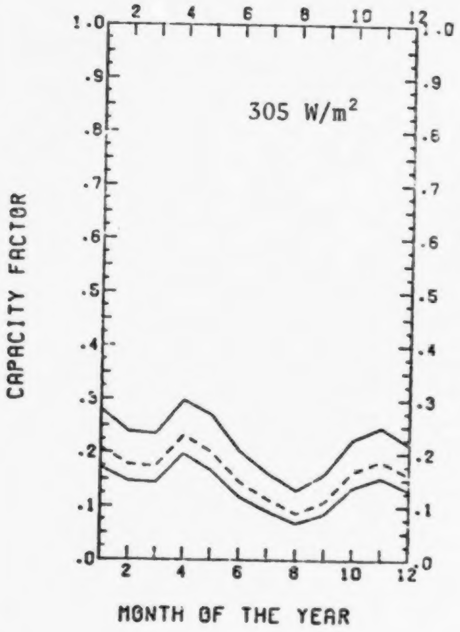
Location: Duluth



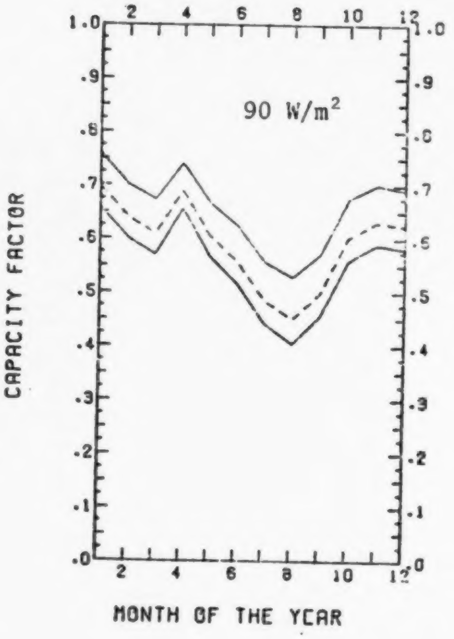
Location: Duluth



Location: Duluth

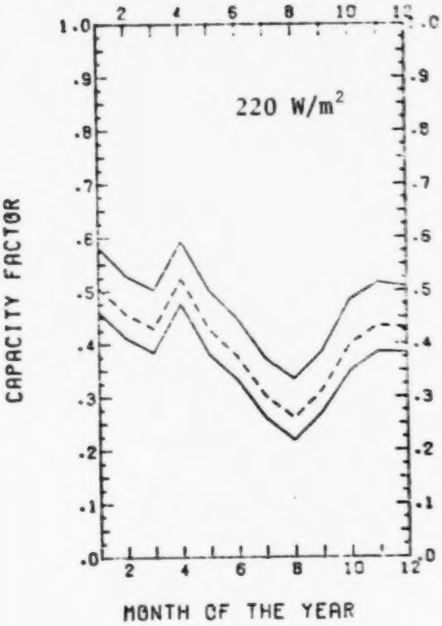


Location: Rochester

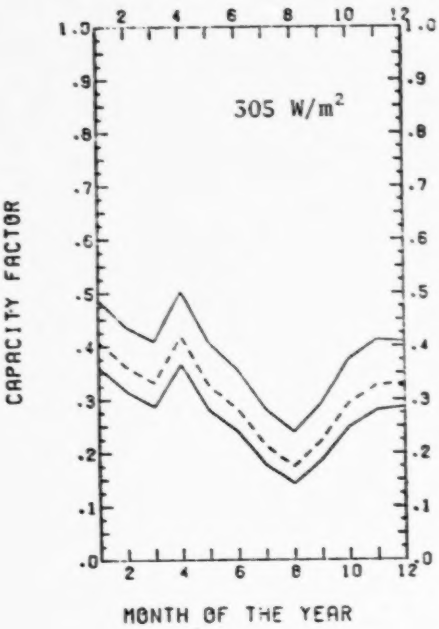


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

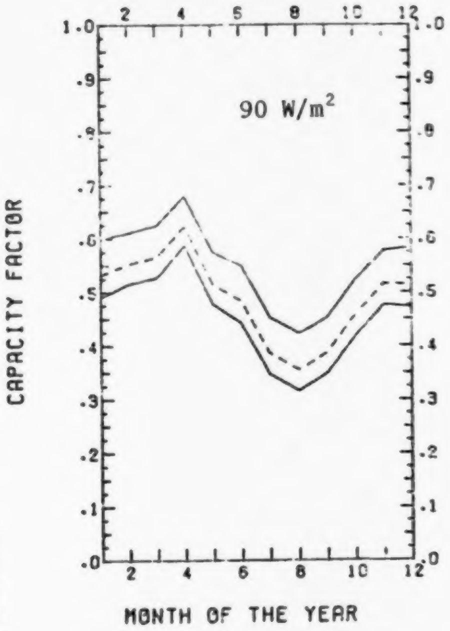
Location: Rochester



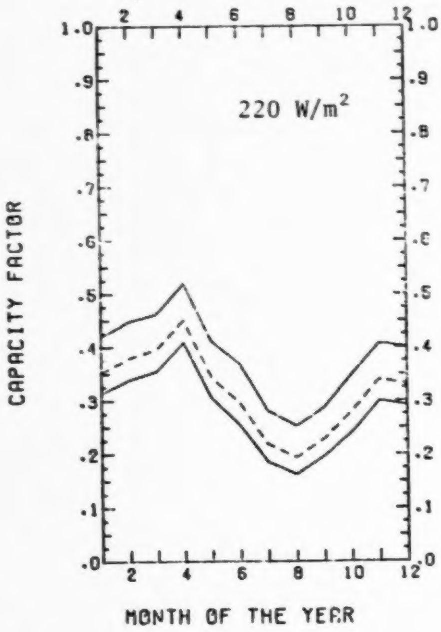
Location: Rochester



Location: Waterloo

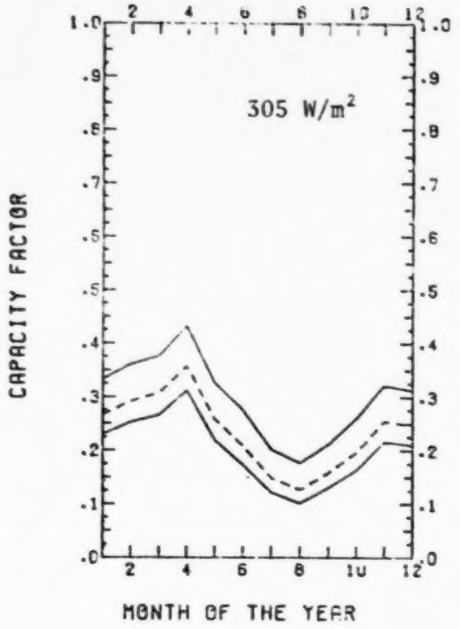


Location: Waterloo

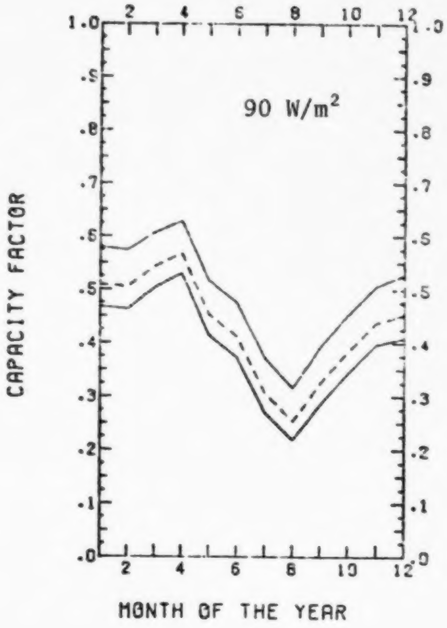


MONTHLY AVERAGE CAPACITY FACTOR AT HEIGHT 20, 30, 60 METERS

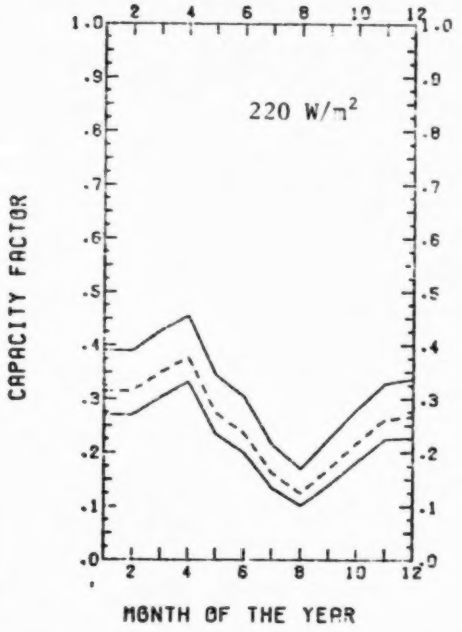
Location: Waterloo



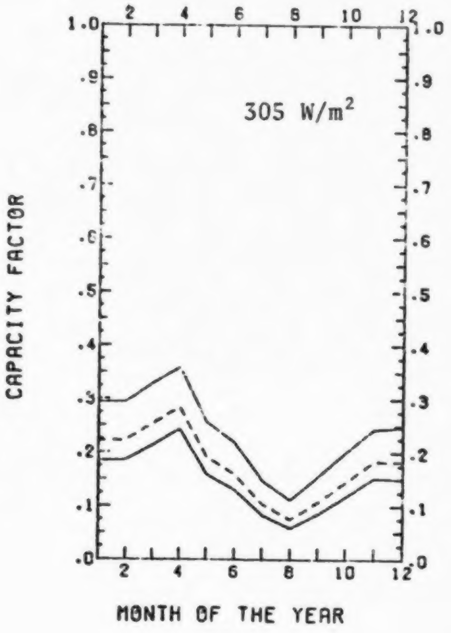
Location: Rockford



Location: Rockford



Location: Rockford



APPENDIX D

ANNUAL AVERAGE POWER DURATION CURVES FOR THREE WIND MACHINES WITH RATED POWER DENSITIES OF 90, 220, AND 305 W/M^2 AT 60-M HEIGHT FOR 12 LOCATIONS IN WISCONSIN AND SURROUNDING STATES

Annual average wind speed (m/sec) for 6 yr for locations in and around the state of Wisconsin. Height adjustment with simple power law exponent equal to 0.14. Wind speed observations, 1969-74, made at a height of approximately 7 m.

	Annual average wind speed (m/sec)			
	Height aboveground (m)			
	7	20	30	60
Madison, Wis.	4.4	5.1	5.4	5.9
Milwaukee, Wis.	5.3	6.1	6.5	7.2
Green Bay, Wis.	4.6	5.3	5.7	6.2
Eau Claire, Wis.	4.5	5.2	5.5	6.1
La Crosse, Wis.	3.4	4.0	4.2	4.6
Duluth, Minn.	4.7	5.4	5.8	6.4
Minneapolis, Minn.	4.5	5.3	5.6	6.2
Rochester, Minn.	5.9	6.8	7.3	8.0
Mason City, Iowa	5.1	6.0	6.3	7.0
Waterloo, Iowa	5.1	6.0	6.3	7.0
Rockford, Ill.	4.6	5.4	5.7	6.3
Moline, Ill.	4.4	5.2	5.5	6.0

Data averaged over 1969-74. One-seventh-power law is used for height adjustments of wind speeds.

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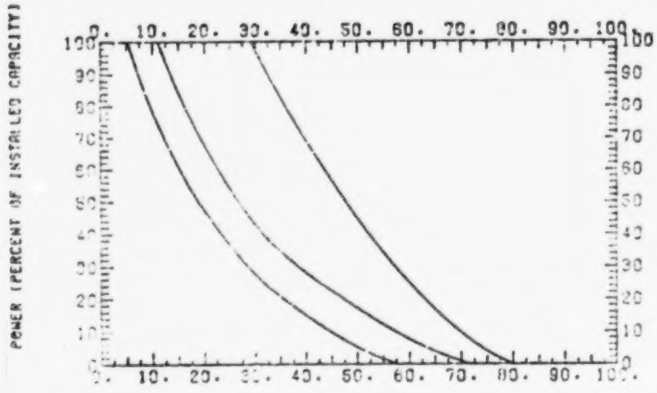
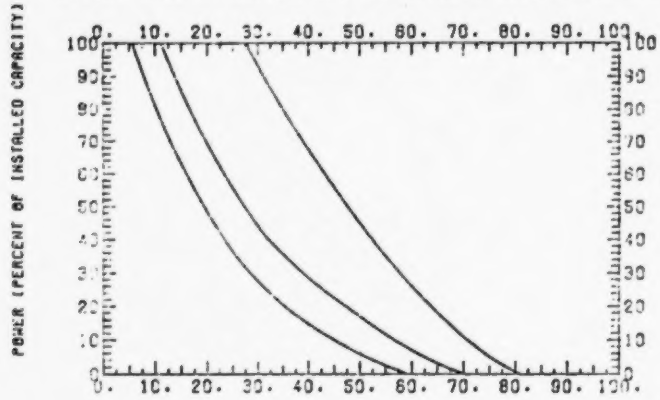
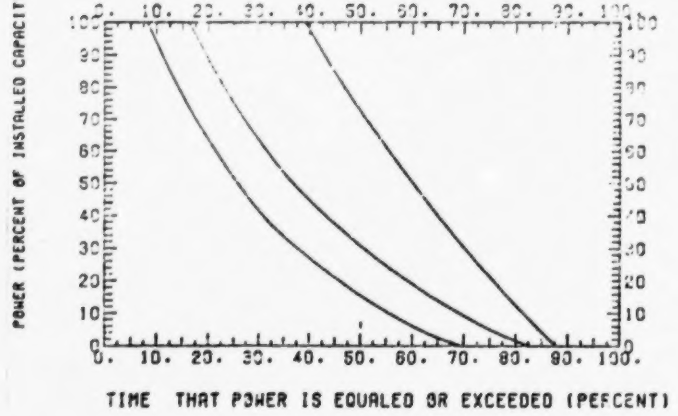
ANNUAL AVERAGE POWER DURATION CURVE: EAU CLAIRE, WIS.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2

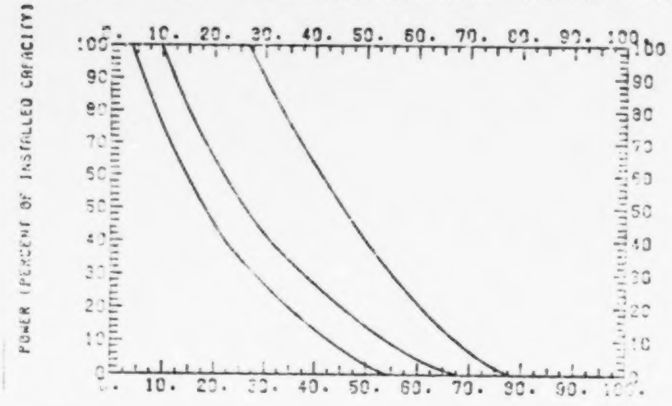


ANNUAL AVERAGE POWER DURATION CURVE: GREENBAY,WIS.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2

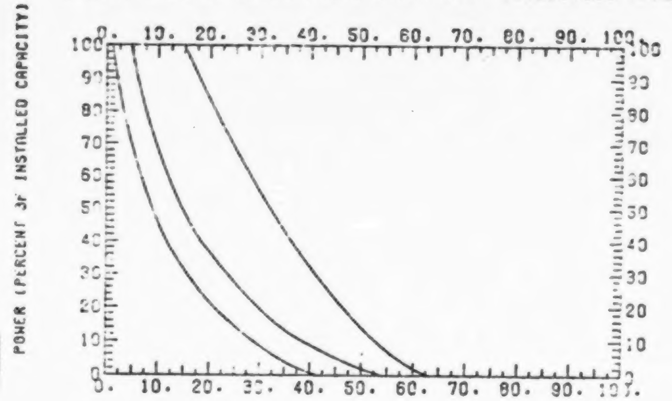


ANNUAL AVERAGE POWER DURATION CURVE: MILWAUKEE,WIS.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2

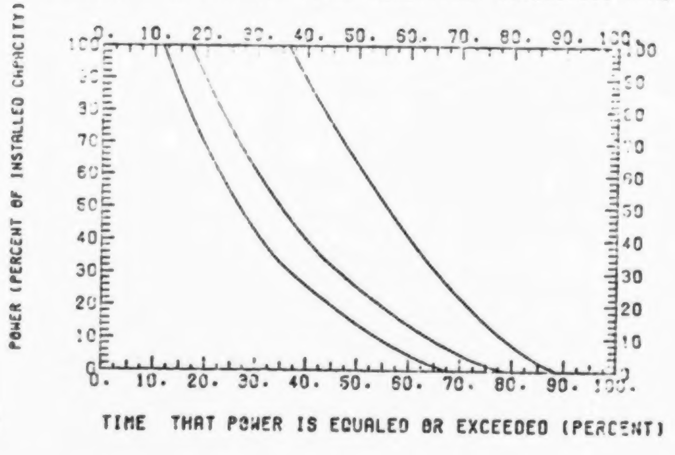




ANNUAL AVERAGE POWER DURATION CURVE: MADISON, WIS.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



ANNUAL AVERAGE POWER DURATION CURVE: LA CROSSE, WIS.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



ANNUAL AVERAGE POWER DURATION CURVE: MASON CITY, IA.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2

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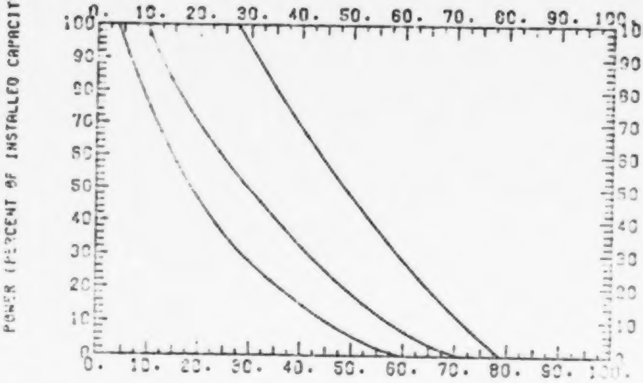
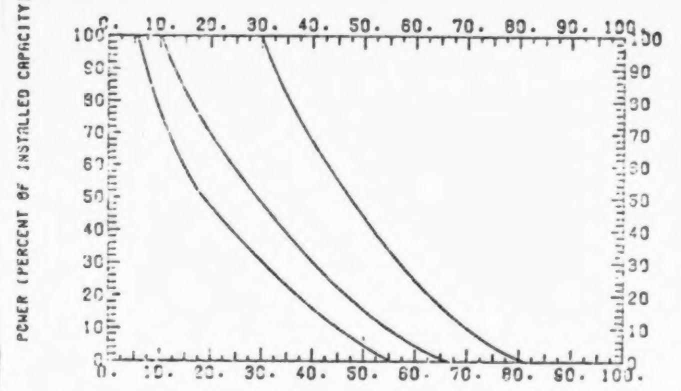
ANNUAL AVERAGE POWER DURATION CURVE: MINNEAPOLIS, MIN.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



ANNUAL AVERAGE POWER DURATION CURVE: MOLINE, ILL.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



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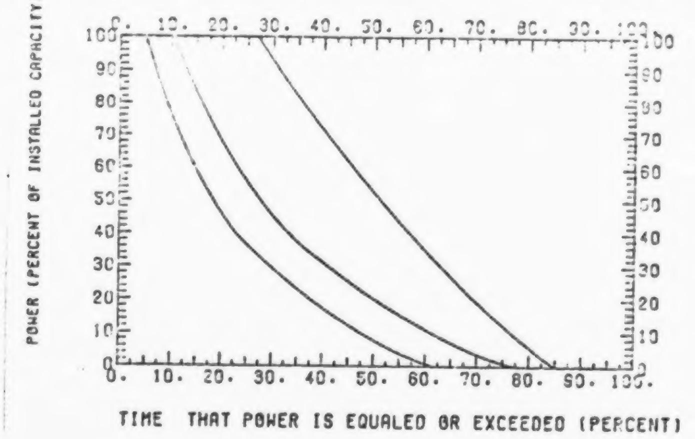
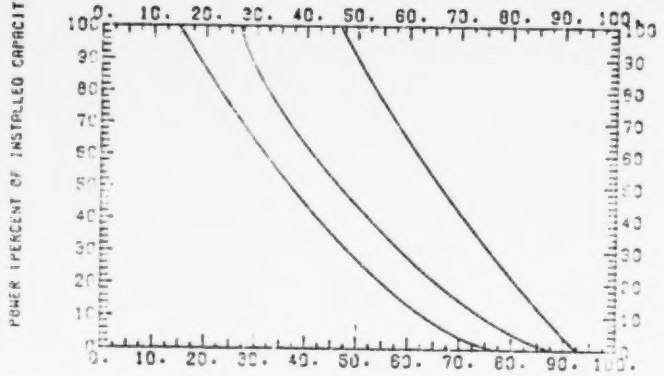
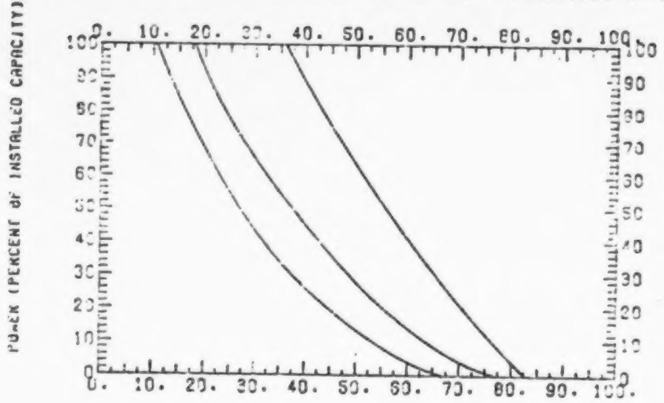
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



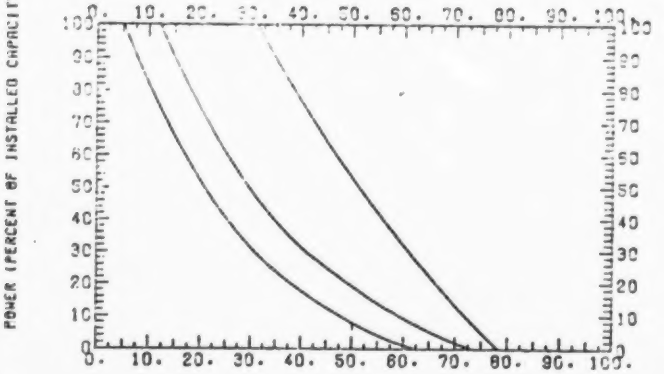
ANNUAL AVERAGE POWER DURATION CURVE: ROCHESTER, MIN.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



ANNUAL AVERAGE POWER DURATION CURVE: WATERLOO, IA.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



ANNUAL AVERAGE POWER DURATION CURVE: ROCKFORD, ILL.
HEIGHT = 60 M. RATED POWER DENSITIES: 90.220.305 W/M2



TIME THAT POWER IS EQUALED OR EXCEEDED (PERCENT)

APPENDIX E

OVERVIEW OF WIND MACHINE AND SITE-DEPENDENT COST ESTIMATES OF LARGE WIND ENERGY SYSTEMS*

DATA SOURCES FOR THE JBF SCIENTIFIC CORPORATION (1977a) STUDY

Title	Contractor	Subject
Design study of wind turbines 50 to 3,000 kW for electric utility applications - analysis and design	Kaman Aerospace	Machine design study
Design study of wind turbines 50 to 3,000 kW for electric utility applications - analysis and design	General Electric	Machine design study
Wind energy mission analysis	General Electric	Mission analysis
Wind energy mission analysis	Lockheed-CA	Mission analysis
Wind power for the California aqueduct	The Aerospace Corporation	Regional analysis
The application of wind power systems to the services area of the Minnesota Power and Light Company	Honeywell, Inc.	Regional analysis
Applications study of wind power technology to the city of Hart, Mich.	Michigan State	Regional analysis
Operational, cost, and technical study of large wind power systems integrated with our existing electric utility	Southwest Research	Regional analysis

Note: The following tables are practically identical to those in Appendix B of the JBF Scientific Corporation report, with a few minor changes.

MACHINE COSTS (IN $1,000)

Data source (report)	Honeywell	SWRI	Aerospace	GE study	Kaman study	Lockheed
Source of machine costs	Boeing	Boeing	GE study	GE study	Kaman study	Lockheed
Production quantity	1,000	1,000	100	100	1,000	10,000
Component[a]						
Engineering			6	22		
Rotor			245	185		
Rotor subsystem	92	83			169	153
Rotor shaft, bearings	10					
Hub						124
Transmission	135	119	151	162	157	
Gearbox and drive						93
High speed shaft, brake, clutch couplings	11	17				19
Generator	20					
Generator controls	19	19				
Electrical	25	42	69	61	56	24
Controls				14	27	36
Nacelle	27	47				
Platform						25
Pintle and nacelle			34			
Foundation						40
Bedplate/pintle				36		
Turntable	20					
Tower	90	91	59	56		57
Assembly				9		
Structure subsystem					117	
Subtotal	449	418	558	529	548	571
Total with indirect costs	516	483	716[b]	607	632	658
$/kW	459/kW	$483/kW	$477/kW	$405/kW	$421/kW	$658/kW
Modified machine costs ($/kW)	$534/kW[c]	$562/kW[c]	$477/kW	$405/kW	$490/kW[d]	$889/kW[d]

[a] Different component names were used in each report, hence a blank in the table does not necessarily mean missing data.

[b] Includes a 7% contingency.

[c] Modified from 1,000 to 100 unit production.

[d] Modified from 10,000 to 100 unit production.

WECS SITE DEPENDENT COSTS (IN $1,000)

Costs	Lockheed	GE Study	Kaman study	Aerospace	Honeywell	SWRI
Transportation	16	10				45
Assembly and erection	67	30			52	58[e]
Installation						
Site preparation	27					
Building and appurtenances						80[f]
Land and right of way				11[g]		
Distribution and network connection				29[h]		
Totals	110	40[i]	89[j]	40	97	138
$/kW	110	27	59	27	86	138
Normalized costs[k] ($/kW)	149	27	69	27	100	160

[e] Estimated to be approximately 10% of capital cost.

[f] SWRI set at 80,000 for building and controls (unspecified).

[g] Land, improvements, and miscellaneous facilities.

[h] Based upon 200 ft WECS spacing center to center.

[i] Costs include assembly of nacelle, site delivery, erection, and system checkout.

[j] Costs include transporting, erecting, readying the system on the site, costs of acquiring and preparing the site, and providing necessary facilities and security.

[k] Prices normalized to 100 units using 95% learning curve.

WECS CAPITAL COSTS SUMMARY ($/kW)

	Lockheed	GE study	Kaman study	Aerospace	Honeywell	SWRI
A. Unmodified machine costs	658	405	421	477	459	483
B. Unmodified site dependent costs	110	27	59	27	86	138
C. Sum of A and B	768	432	480	504	545	621
D. Normalized machine costs	889	405	490	477	534	562
E. Normalized site costs	149	27	69	27	100	160
F. Sum of D and E	1,038	432	559	504	634	722
G. $\$/m^2$ rotor swept area	139	249	527	206	138	137

A useful relationship between energy cost factors is shown in the equation below and may be used to determine values for parameters not specifically stated in the reports.

$$C_e = \frac{1.14 C_c R}{C_f} \times 10^{-3}$$

where: C_e = the energy cost (mills/kWh)

C_c = the capital cost ($/kW)

R = the total annual cost, including fixed costs, O and M, overhead, and taxes (in % of capital costs)

C_f = the capacity factor

APPENDIX F

BETZ'S MAXIMUM EFFICIENCY OF WIND POWER EXTRACTION (AFTER WILSON ET AL. 1976)

AXIAL MOMENTUM THEORY

The function of a wind turbine is to extract energy from the air and to produce mechanical energy which later may be transformed into other forms of energy. Energy losses, in additon to the energy extracted, are attributed to the rotational motion of the fluid that is imparted by the blades and frictional drag. As a first approximation to determine the maximum posible output of a wind turbine, the following assumptions are made:

(1) Blades operate without frictional drag.

(2) A slipstream that is well defined separates the flow passing through the rotor disk from that outside the disk.

(3) The static pressure in and out of the slipstream far ahead of and behind the rotor are equal to the undisturbed free-stream static pressure ($p_2 = p_\infty$).

(4) Thrust loading is uniform over the rotor disc.

(5) No rotation is imparted to the flow by the disc.

Applying the momentum theorem to the control volume in the figure on the next page, where the upstream and downstream control volume planes are infinitely far removed from the turbine plane, one obtains:

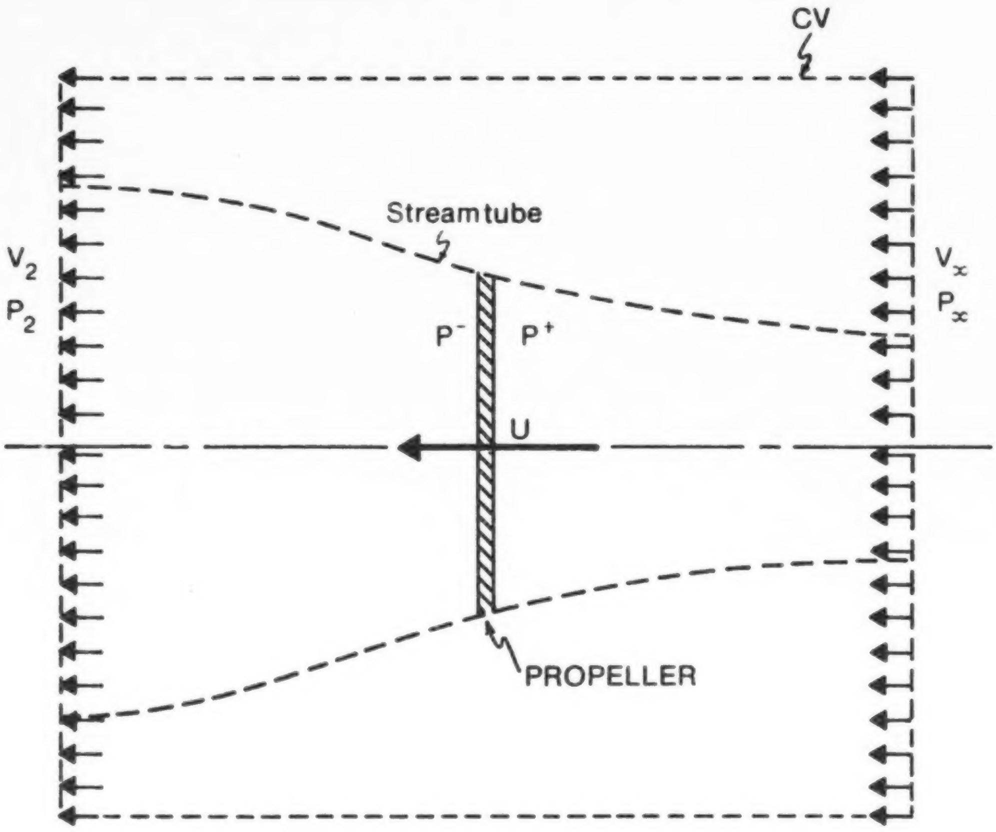
$$-T = \text{Momentum flux out} - \text{momentum flux in}$$

$$T = m(V_\infty - V_2) = \rho AU(V_\infty - V_2) \qquad (11)$$

Also from the pressure conditions, the thrust can be expressed as:

$$T = A(P^+ - P^-) \qquad (12)$$

Now applying Bernoulli's equation to flow upstream of the wind turbine one obtains:


CV
Streamtube
V_2
P_2
V_∞
P_∞
P^-
P^+
U
PROPELLER

Control volume of a wind turbine (Lissaman and Walker 1976).

$$\frac{1}{2}\, V_\infty^{\ 2} + P_\infty = \frac{1}{2}\, U^2 + P^+ \tag{13}$$

and downstream of the wind turbine,

$$\frac{1}{2}\, V_2^2 + P_\infty = \frac{1}{2}\, U^2 + P^- \tag{14}$$

or by subtracting these equations:

$$P^+ - P^- = \frac{1}{2}\rho(v_\infty^{\ 2} - V_2^{\ 2})$$

Substituting into Eq. (12) gives:

$$T = \frac{1}{2}\rho A(V_\infty^{\ 2} - V_2^{\ 2}) \tag{15}$$

Now, combining Eq. (15) with (11) provides:

$$\frac{1}{2}\rho A(V_\infty^{\ 2} - V_2^{\ 2}) = AU(V_\infty - V_2)$$

or

$$U = \frac{V_\infty + V_2}{2} \tag{16}$$

This result states that the velocity through the turbine is the average of the wind velocity ahead of the turbine and wake velocity after the turbine. Now defining the axial induction factor "a" by:

$$U = V_\infty(1-a)$$

and using the definition of "a" and Eq. (16) gives:

$$V_\infty(1-a) = \frac{V_\infty + V_2}{2}$$

then the wake velocity can be expressed as:

$$V_2 = V_\infty(1-2a)$$

The wake-induced velocity is twice that of the induced velocity in the plane of the rotor. Therefore:

$$a = 1 - \frac{V_\infty + V_2}{2V_\infty} \tag{17}$$

which implies that if the rotor absorbs all the energy, i.e., $V_2 = 0$, then "a" would have a maximum value of 0.5. Because power is given by mass flow rate times the change in kinetic energy, the power P is:

$$P = \dot{m}\ \mathrm{KE} = \rho AU \quad \frac{V_\infty^{\ 2}}{2} - \frac{V_2^{\ 2}}{2} = \tfrac{1}{2}\rho AV_\infty^3\ 4a(1-a)^2$$

or

$$P = 2\rho AV_\infty^{\ 3}a(1-a)^2 \tag{18}$$

Maximum power occurs when:

$$\frac{dP}{da} = 0$$

$$= 2\rho AV_\infty^{\ 3}(1-4a+3a^2) = 0$$

or

$$a = 1 \text{ or } 1/3$$

Maximum power occurs when a = 1/3, so:

$$P_{max} = \frac{16}{27}\left(\tfrac{1}{2}\rho A_\infty V^3 \right) = 0.593 \left(\tfrac{1}{2}\rho AV_\infty^3\right).$$

The power coefficient equals approximately 0.593.

SYMBOLS

a = Exponent of the height adjustment power law

A = Swept area of a wind machine rotor (m^2)

C_p = Power coefficient of a wind machine

e = Annual fuel price increase, including inflation (%)

E_s = Specific energy output of a wind machine (kWh/kW/time)

f = Energy pattern factor

F_p = Capacity factor of a wind machine

GWh = Gigawatt hour

i = Interest or discount rate, icluding inflation (%)

I_{BE} = Break-even capital cost of a WECS ($/kW)

MW = Megawatt

P_w = Power in the wind (W)

P_{wd} = Power density of the wind (W/m^2)

$P(v)$ = Instantaneous power output of a wind machine (W)

$\overline{P}$ = Average power density of a wind machine (W)

$P_d(v)$ = Instantaneous power density output of a wind machine (W/m^2)

$\overline{P}_d$ = Average power density output of a wind machine (W/m^2)

P_r = Rated power of a wind machine (W)

P_{rd} = Rated power density of a wind machine (W/m^2)

= Density of air (kg/m^3)

v = Wind speed (m/sec)

v = Wind speed averaged over time (m/sec)

v_o = Cut-in wind speed of a wind machine (m/sec)

v_r = Rated wind speed of a wind machine (m/sec)

v_2 = Cut-out wind speed of a wind machine (m/sec)

z = Height of wind speed observation (m)

z_0 = Aerodynamic roughness of the ground surface (m)